ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

201 South Main, Suite 2300
Salt Lake City, Utah 84111

April 29, 2011

VIA OVER NIGHT DELIVERY

Idaho Public Utilities Commission
472 W. Washington
Boise, ID 83702-5983

Attn: Jean D. Jewell
Commission Secretary

Re: 2010 Annual Report of Idaho Demand Side Management Activities

PacifiCorp (d.b.a. Rocky Mountain Power) hereby submits for filing an original and seven copies of its 2010 Demand Side Management Annual Report, pursuant to Order No. 29976 from Case No. PAC-E-05-10.

Rocky Mountain Power respectfully requests that all formal correspondence and requests regarding this filing be addressed to one of the following:

By E-mail (preferred): datarequest@pacificorp.com

By regulator mail: Data Request Response Center
PacifiCorp
825 NE Multnomah Blvd., Suite 2000
Portland, OR 97232

For any informal questions, please contact Ted Weston, Manager, Idaho Regulatory Affairs, at (801) 220-2963.

Sincerely,

Jeffrey Larsen / RCY

Jeffrey K. Larsen
Vice President, Regulation

Enclosure

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Rocky Mountain Power

Energy Efficiency and Peak Reduction Annual Report - Idaho

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Introduction and Executive Summary

Rocky Mountain Power (the "Company") working in partnership with its retail customers and with the approval of the Idaho Public Utilities Commission (the "IPUC"), acquires energy efficiency and peak reduction resources as an alternative to the acquisition of supply-side resources. These resources assist the Company in efficiently addressing load growth and contribute to the Company's ability to meet system peak requirements. Company energy efficiency and peak reduction programs provide participating Idaho customers with tools that enable them to reduce or assist in the management of their energy usage, while reducing the overall costs to Rocky Mountain Power's customers. These resources are a valuable component of Rocky Mountain Power's resource portfolio and are relied upon in resource planning as a least cost alternative to supply–side resources.

Rocky Mountain Power currently offers seven energy efficiency and peak reduction programs in Idaho. In 2010, costs associated with these programs were and are being recovered through the Customer Efficiency Services Rate Adjustment (Schedule 191), with the exception of the Load Control Service Credits which were paid to participants of the irrigation load control programs (Schedule 72 and 72A) and recovered through general rates. Effective December 28, 2010, the IPUC directed the Company to recover all Schedule 72A costs through general rates, (Order No. 32196). The results of Rocky Mountain Power's Idaho energy efficiency and peak reduction programs for the reporting period of January 1, 2010 through December 31, 2010 are summarized in Table 1 below.

Table 1: Total Portfolio Performance

2010 Total Portfolio Performance					
System Benefit Revenues Collected			$ 5,939,833		
System Benefit Expenditures (Excludes Irrigation Credits)			$ 7,515,026		
Total Expenditures Including Irrigation Credits			$ 15,615,708		
MW Under Control (Gross at Generation)			308.1		
kWh/Yr Savings (Gross at Generation)			13,095,503		
kWh/Yr Savings (Gross at Site)			11,962,957		
	PTRC	TRC	UCT	RIM	PCT
Portfolio Cost Effectiveness	2.613	2.376	1.246	0.913	7.010

(Note: See notes for Table 2 for explanation of Gross Savings and line loss assumptions)

Participation in the irrigation load control programs increased from 285.2 MW[1] in 2009 to 308.1 MW in 2010. Overall first year energy savings for 2010 achieved through energy efficiency

[1] Sum of the average years of billing demand for June, July and August for participating loads at the meter values (Value at site 282.5, Gross up for Line Losses at 9.06% = 308.1).

programs, decreased approximately 20 percent while Customer Efficiency Services expenditures increased 14 percent.

At the end of 2010, the Customer Efficiency Services balancing account had an unfunded balance of $ 3,845,843.

During 2010, the Company completed process and impact evaluations for several Idaho programs including the Home Energy Savings, Refrigerator Recycling, Energy FinAnswer, FinAnswer Express and Agricultural Energy Services programs for program years 2006 to 2008. The evaluation work was being completed by an independent evaluator. Final reports for the evaluations are available at www.pacificorp.com/es/dsm/idaho.html

Rocky Mountain Power's energy efficiency and peak reduction portfolio was cost effective under four of the five cost effectiveness tests based on 2010 results. The Ratepayer Impact Test (RIM) benefit/cost ratio of less than 1.0 indicates that the portfolio put some upward pressure on overall rates (all things being the same) due to a reduction in Company kWh sales as a result of the energy efficiency.

For the period January 1, 2010 through December 31, 2010, energy efficiency and peak reduction acquisitions for all programs produced an estimated $19.5 million in net benefits over the life of the savings on a Total Resource Cost basis.

2010 Performance and Activity

Program and Sector level results for 2010 are provided on the following table[2]. Program Schedules are noted in parenthesis in the table.

Table 2: Energy Efficiency and Peak Reduction Annual Results

Idaho Annual Results for 2010

Program	Units	kW (at site)	kW/Yr Savings (at generator)	Program Expenditures
Irrigation Load Control (72 and 72A)	2,316	282,500	308,080	$ 4,283,393
Total Load Control	**2,316**	**282,500**	**308,080**	**$ 4,283,393**
Program	**Units**	**kWh/Yr Savings (at site)**	**kWh/Yr Savings (at generator)**	**Program Expenditures**
Low Income Weatherization (21)	43	71,346	78,448	$ 133,673
Refrigerator Recycling (117)	788	1,035,567	1,138,658	$ 165,801
Home Energy Savings (118)	6,400	3,330,684	3,662,254	$ 1,305,014
Total Residential	**7,231**	**4,437,597**	**4,879,360**	**$ 1,604,488**
Energy FinAnswer (125)	0	0	0	$ 47,203
FinAnswer Express (115)	44	3,454,427	3,776,587	$ 513,478
Total Commercial	**44**	**3,454,427**	**3,776,587**	**$ 560,681**
Energy FinAnswer (125)	10	1,475,439	1,609,040	$ 321,983
FinAnswer Express (115)	2	80,325	87,598	$ 107,012
Agricultural Energy Services (155)	155	2,515,169	2,742,918	$ 637,009
Total Industrial	**167**	**4,070,933**	**4,439,556**	**$ 1,066,004**
Market Transformation				
Northwest Energy Efficiency Alliance		0	0	$ 461
Total Energy Efficiency		**11,962,957**	**13,095,503**	**$ 3,231,633**

Total System benefit Expenditures - All Programs	**$ 7,515,026**
Load Control Participation Credits 2010	$ 8,100,681
Total Idaho Program Expenditures	**$ 15,615,708**

[2] Savings values in this table are shown prior to any net-to-gross adjustment. The values at generation include line losses between the customer site and the generation source. The Company's line losses by sector are 9.96 percent for residential, 9.33 percent for commercial and 9.06 percent for industrial. These values are based on the Company's 2007 Transmission and Distribution Loss Study by Management Applications Consulting published in October 2008.

Major Trends and Activities

In 2010, the Company realized increases and decreases in energy efficiency and peak reduction acquisitions in a variety of sectors and programs. At a sector lever, the Residential Sector realized 75 percent higher savings on a kWh/year basis compared to 2009, and the combined business and agricultural sectors delivered 18 percent more kWh/year savings than in 2009. There were no savings realized from Northwest Energy Efficiency Alliance in 2010 which resulted in a decrease of the overall first year energy savings.

Expenditures related to program delivery increased in 2010 as compared to 2009. Overall expenditures for energy efficiency and peak reduction programs (excluding Irrigation Load Control participation credits) increased by 17 percent compared to 2009. When irrigation load control participation credits are included, expenditures increased by 14 percent in 2010 compared to 2009. At a sector level, the residential sector expenditures increased by 78 percent, business and agricultural sectors increased by 14 percent and peak reduction increased by 12 percent.

Cost Effectiveness

Consistent with the requirements outlined in Memorandum of Understanding signed by the Company and Idaho Commission Staff, the Company provides cost effectiveness results utilizing five cost effectiveness tests:

1. PacifiCorp Total Resource Cost Test (PTRC) which includes a 10 percent additional benefit for demand-side resources. Total Resource Cost Test (TRC)
2. Utility Cost Test (UCT)
3. Ratepayer Impact Test (RIM)
4. Participant Cost Test (PCT)

The PTRC (also referred to as the TRC + Conservation Adder) is a variation of the TRC test. It includes a 10 percent benefit adder to account for non-quantified benefits of conservation resources over supply-side alternatives. This is consistent with Northwest Power Planning and Conservation Act.

The TRC compares the total cost of a supply side resource to the total cost of an energy efficiency program resource, including costs paid by the customer in excess of the program incentives provided. This test is used to determine if an energy efficiency program is cost effective from a total cost perspective.

The UCT, also referred to as the Program Administrator Test compares the portion of the resource costs paid directly by the Company and recovered through the tariff rider revenues. This test is useful in determining the cost effectiveness of the resource from the Company's perspective; however it does not account for the portion of the cost that is borne directly by customers.

The RIM test determines the impact an energy efficiency program has on rates. The ultimate objective of an energy efficiency program is to encourage customers to use less energy, thereby reducing energy sales. The RIM test accounts for the lost revenues to the utility and associated kWh sales reductions. The net impact of these reductions can put upward pressure on rates even when total costs and utility costs are lower with a successful energy efficiency program than with a supply-side alternative. One challenge with the RIM test however is that its more sensitive than the other tests to differences between long-term projections of marginal costs and long-term projections of rates, two cost streams that are difficult to quantify with certainty.

The PCT[3] test compares the portion of the resource cost paid directly by participants to the savings realized by the participant. For the PCT test, bill savings are the realized benefit of energy efficiency rather than the avoided supply-side costs.

The results for each test are provided at several levels:

1. Overall portfolio level, consolidation of all Company delivered programs
2. Load control and energy efficiency program portfolio
3. Residential and non-residential energy efficiency program portfolio
4. Individual program

Results of the cost effectiveness tests are included in the summary overview for each program. Further details including key inputs and assumptions for each of the cost effectiveness tests are provided in the cost effectiveness section of this report.

[3] The calculation of the PCT methodology has changed from previous calculations. For prior cost-effectiveness analyses, the vendor used Slick Dice, an Excel based cost-effectiveness model. The vendor is now using DSM Portfolio Pro, which handles all of the analysis programmatically. A minor difference between the two models impacts how the PCT is calculated. Slick Dice calculated PCT costs as the out-of-pocket costs and PCT benefits as avoided bills. DSM Portfolio Pro uses the full incremental cost of the measures for PCT costs; benefits are calculated as avoided bills plus the utility incentive. Both are valid approaches and result in the same net benefits. The approach used in DSM Portfolio Pro more strictly adheres to the California Standard Practice Manual and avoids B/C ratio issues caused by $0 costs.

Program Evaluation

Rocky Mountain Power agreed to provide a timeline for when evaluations would be completed for each program offered in the state. The Program Evaluation Timeline (Table 3 below) provides an outline of evaluations for each program in Rocky Mountain Power's energy efficiency and peak reduction portfolio.

Table 3: Program Evaluation Timeline

Program	Evaluation Type	Status	Anticipated Year Complete	Program Year(s) Evaluated	Evaluator
Home Energy Saver	Process and Impact	Planning	2011	2009-2010	To Be Determined
See Ya Later Refrigerator	Process and Impact	Planning	2011	2009-2010	To Be Determined
Low Income Weatherization	Process and Impact	Complete	2011	2007-2009	Cadmus
Low Income Weatherization (Pending application to remove program evaluation requirement)	Process and Impact	Planning	2013	2010-2012	To Be Determined
Energy FinAnswer	Process and Impact	Planning	2012	2009-2011	To Be Determined
FinAnswer Express	Process and Impact	Planning	2012	2009-2011	To Be Determined
Irrigation Energy Savers	Process and Impact	Planning	2012	2009-2011	To Be Determined
Irrigation Load Control	Process and Impact	Planning	2012	2011-2012	To Be Determined
Irrigation Load Control	Impact	Complete	2011	2009-2010	Cadmus

During 2010, the Company received third-party independent process and impact evaluations for the Home Energy Savings, See ya later refrigerator, Energy FinAnswer, FinAnswer Express and Agricultural Energy Services programs for program years 2006 – 2008. The results of these evaluations are available on the Company web site at http://www.pacificorp.com/es/dsm.html for public viewing. Findings from these evaluations will be key inputs to ongoing program design and modification as well as inputs to future cost effectiveness determinations.

Company Filings with the Idaho Public Utilities Commission

The Company made several filings with the Commission regarding its energy efficiency and peak reduction programs during 2010. Summary information concerning these filings is provided below.

On February 25, 2010, Rocky Mountain Power filed an application with the Commission requesting to increase the Customer Efficiency Services rate, which is administered through Schedule 191. This matter was subsequently assigned to Case No. PAC-E-10-03. Through the application, the Company proposed the collection rate be increased from 3.72 percent to 5.85 percent effective May 1, 2010. The increase was requested to facilitate the funding of ongoing demand-side management expenditures in Idaho and to reduce an unfunded balance that had accrued in the demand-side management balancing account. On June 30, 2010, the Commission issued an order approving an increase in the collection rate to 4.72 percent effective July 1, 2010.

On March 15, 2010, the Company submitted its 2009 Idaho Demand-Side Management Annual Report with the Commission.

Rocky Mountain Power submitted Tariff Advice No. 10-02 with the Commission on July 14, 2010 proposing modifications to the Irrigation Load Control Credit Rider program, which is administered through Schedule 72. This filing was subsequently revised by the Company through a filing submitted with the Commission on August 20, 2010. Through Tariff Advice No. 10-02, the Company proposed various modifications to program administration and revisions to improve the clarity of the tariff language and to align tariff language with program operations. The Commission approved the tariff revisions effective August 30, 2010.

On December 16, 2010, Rocky Mountain Power submitted Tariff Advice No. 10-03 with the Commission proposing modifications to the FinAnswer Express program, which is administered through Schedule 115. The primary purpose of this filing was to align program qualifications with changing energy codes. The Commission approved the modifications proposed through this filing with an effective date of January 15, 2011.

Peak Reduction Program and Activity

Peak Reduction programs assist the Company in balancing the timing of customer energy requirements during heavy use hours; deferring the need for higher cost investments in delivery infrastructure and generation resources that would otherwise be needed to serve those requirements for a select few hours each year. These programs help the Company maximize the efficiency of the Company's existing electrical system and reduce costs for all customers.

Programs targeting capacity related resources are often specific to end use loads most prevalent in a given jurisdiction, such as the agricultural pumping loads in the Company's Idaho service territory. The Company offers two peak reduction programs in Idaho; a pre-schedule and on-call or dispatchable irrigation load control program. For the purpose of this report the two programs are being combined and evaluated as one program.

Table 4: Load Management Portfolio Performance

2010 Load Management Portfolio Performance					
kW Under Control (Gross - At Gen)	308,080				
kW Under Control (At Site)	282,500				
Total Expenditures	$ 12,384,074				
Participation Credits	$ 8,100,681				
	PTRC	TRC	UCT	RIM	PCT
Program Cost Effectiveness	3.19	2.90	1.00	1.00	NA
Levelized Cost ($/kWh)	NA	NA	NA		
Lifecycle Revenue Impact ($/kWh)	NA				

Irrigation Load Control (Schedule 72 and 72A)

Irrigation Load Control (Schedules 72 & 72A) is offered to Idaho irrigation customers receiving retail electric service on Schedule 10. Participants agree to allow for the curtailment of their electricity usage as prescribed in Schedules 72 and 72A in exchange for a participation credit.
A summary of the program performance, expenditures, participation and cost effectiveness results are provided in table 5:

Table 5: Irrigation Load Control Program Performance[4]

2010 Irrigation Load Control Program Performance					
MW Under Control (Gross at Gen)	308.1				
Expenditures - Total	$ 12,384,074				
Participation Credits	$ 8,100,681				
Program Operations Expense	$ 4,283,393				
Participation (Customers)	878				
Participation (Sites)	2,316				
	PTRC	TRC	UCT	RIM	PCT
Program Cost Effectiveness	3.190	2.900	1.000	1.000	NA
Levelized Cost ($/kWh)	NA	NA	NA		
Lifecycle Revenue Impact ($/kWh)	NA				

Additional information regarding major trends and activities, program evaluations, and plans for the irrigation load control programs are available in the ***2010 Idaho Irrigation Load Control Quantitative Review*** (Appendix 2) dated January 7, 2011.

Major Trends and Activities

During 2010, participating sites increased 13 percent which increased MW under control savings by 8 percent when compared to 2009. As a result, the participation credits and program expenditures increased 12 percent respectively from 2009 to 2010.

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4 The 2009 report used MW under management of 285.5 in the calculation of program benefit to cost ratios. A scheduling restriction was implemented in 2010 to accommodate the Grid control voltage limitations. While this did not impact hourly realization rates, it did have a significant effect on the difference between the nominal loads and the aggregated reductions achieved. In 2010, the maximum hourly load reduction was 156 MW (Calculation - Gross up for Line Losses at 9.06% = 170.1) for all Idaho irrigation program loads. See Impacts of Rocky Mountain Power's Idaho Irrigation Load Control Program evaluation from Cadmus. www.pacificorp.com/es/dsm/idaho.html

Cost Effectiveness

The program was cost effective from all perspectives. Appendix 1 provides detailed inputs used in the cost effectiveness analysis of this program.

Program Evaluation

See comments under the Program Evaluation heading in the 2010 Performance and Activities section of this report for evaluation activities related to this program.

Plans for 2011

The company has entered into a stipulation with the Idaho Irrigation Pumpers Association and the Idaho Public Utilities Commission staff related to the structure and operation of the company's Dispatchable Irrigation Load Control Credit Rider Program (Schedule 72A.) If approved by the Idaho Public Utilities Commission the following changes will be implemented:

- participation of the program will be restricted for the 2011 and 2012 control period,
- the terms conditions related to customers electing to opt out of control events will be changed, and
- The incentive payment will be reduced for the 2011 control period.

Energy Efficiency Programs and Activity

Energy efficiency programs deliver sustainable energy savings by improving the efficiency of equipment such as motors, lighting and cooling equipment. Energy efficiency is also delivered through improved weatherization of existing buildings, improving the design features of new facilities by ensuring they are constructed to exceed code. In the industrial sector, improvements in industrial equipment or processes can also improve energy utilization and deliver long term energy efficiency resources. Replacement of existing functional equipment, replacement of equipment at the end of its useful life and improvement opportunities all provide opportunities to deliver energy efficiency resources. While each type of opportunity has unique challenges, improvements in these areas all deliver long term energy savings over the life of the installed equipment.

To deliver resources from these different opportunities, the Company offers six energy efficiency programs; three targeted to residential customers and three targeted to business customers. While customers may receive only one incentive per project or piece of equipment, the programs are designed to work in a coordinated fashion and provide complementary services (i.e. recycle an existing refrigerator after buying a new Energy Star model) or different incentive options (i.e., Energy FinAnswer incentives at the time a project is completed). Some programs or program features are specifically designed to capture lost opportunities (the Design Assistance provision in Energy FinAnswer), while other programs target retrofit or replacement opportunities in existing structures (i.e., FinAnswer Express and Home Energy Savings).

Results for the 2010 Energy Efficiency Portfolio are presented in the following table:

Table 6: 2010 Energy Efficiency Portfolio Performance

2010 Energy Efficiency Portfolio Performance					
System Benefit Expenditures			$ 3,231,633		
Energy Efficiency First Year Savings MWh/Yr (Gross at Generation)			13,095,503		
Energy Efficiency First Year Savings MWh/Yr (at Site)			11,962,957		
	PTRC	TRC	UCT	RIM	PCT
Portfolio Cost Effectiveness	1.978	1.798	2.175	0.788	3.298
Levelized Cost ($/kWh)	$ 0.0521	$ 0.0521	$ 0.0431		
Lifecycle Revenue Impact ($/kWh)	$ 0.0000417				

Residential Energy Efficiency Programs and Activity

Home Energy Savings Program (Schedule 118)

The Home Energy Saver Incentive program (Schedule 118) provides a broad framework to deliver incentives for more efficient products and services installed or received by Idaho customers in new or existing homes, multi-family housing units or manufactured homes. The program is delivered through a third party administrator hired by the Company. Program information is available to the public at the program's web site at http://www.homeenergysavings.net/Idaho/idaho_home.html and can also be accessed through http://www.rockymountainpower.net/env/epi.html, the Company's Idaho energy efficiency program website.

Eligible program measures include: clothes washers, refrigerators, water heaters, dishwashers, lighting (both compact florescent lamps (CFLs) and fixtures), cooling equipment and services, ceiling, wall and attic insulation, windows and miscellaneous equipment such as ceiling fans. Incentives are provided to customers through two methods: (1) post-purchase application process with incentives paid directly to participating customers, and (2) mid-market (i.e., retailers and manufacturers) buy-downs, for delivery of CFL incentives. Mid-market buy-downs result in lower retail prices for customers at point-of-purchase and involve no direct customer application process.

Summary of the program results for 2010 are provided in the table below:

Table 7: Home Energy Savings Program Performance

2010 Home Energy Savings Program Performance					
kWh/Yr Savings 2010 (Gross - At Gen)			3,662,254		
kWh/Yr Savings 2010 (Gross - At Site)			3,330,684		
Expenditures			$ 1,305,014		
Incentives Paid			$ 828,401		
	PTRC	TRC	UCT	RIM	PCT
Program Cost Effectiveness	2.356	2.142	2.262	0.763	3.763
Levelized Cost ($/kWh)	0.0501	0.0501	0.0475		
Lifecycle Revenue Impact ($/kWh)	$ 0.000103				

Details of 2010 measure level participation and savings are provided on the following table:

Table 8: Home Energy Savings Measure Performance

2010 Home Energy Savings Measure Performance

Home Energy Savings Measures	**Unit Measurement**	**# of Units**	**Participants**	**kWh/Yr Savings (Gross - At Site)**
Clothes Washer-Tier One	Units	212	212	50,427
Clothes Washer-Tier Two	Units	1,167	1,167	280,164
Clothes Washer Recycling	Units	0	0	0
Dishwasher	Units	521	521	19,622
Electric Water Heater	Units	99	99	8,979
Evaporative Cooler (Portable)	Units	0	0	0
Evaporative Coolers (Permanently Installed)	Units	1	1	325
Refrigerator	Units	460	460	44,850
Room AC	Units	0	0	0
Insulation: Attic	sq feet	1,361,168	1,080	1,961,621
Insulation: Floor	sq feet	21,667	22	19,517
Insulation: Wall	sq feet	9,400	14	21,261
Windows	sq feet	14,981	129	29,128
CAC Tune up	Projects	98	98	2,940
CAC (15 SEER)	Units	0	0	0
CAC Install	Units	0	0	0
CAC Sizing	Projects	0	0	0
Duct Sealing-Electric	Projects	34	34	1,360
Duct Sealing-Gas	Projects	28	28	1,120
Duct Sealing & Insulation	Projects	0	0	0
Heat Pump Tune-Up	Units	0	0	0
Heat Pump Conversion	Units	0	0	0
Heat Pump Upgrade	Units	1	1	811
Water Source HP (Air Source HP Upgrade)	Units	0	0	0
Water Source HP (Heat System Conversion)	Units	0	0	0
Ceiling Fans	Units	13	7	1,391
Fixtures	Units	84	38	7,728
CFLs-Twisters	Bulbs	24,892	2,489	879,442
CFLs-Specialty Bulbs	Bulbs	0	0	0
Totals		1,434,825	6,400	3,330,684
kWh/Yr Savings at Generation				3,662,254

(Note: CFL participation is assumed at 10 CFLs per participant.)

Major Trends and Activities

The Home Energy Saver Incentive program savings in 2010 increased 147 percent as compared to 2009, while the expenditures increased approximately 120 percent.

The large increase in participation was seen in early 2010 from an upswing in weatherization activity that began in late 2009. The upswing was the result of a few weatherization contractors adjusting their pricing and installations practices so that work was priced at or below the existing incentives. After a review of the incentive levels and recent installation cost data the Company adjusted incentive levels based on heating fuel source, a more relevant screen for electric savings and benefits. After the required noticing period on March 20, 2010 the incentives for weatherization measures were lowered, improving the measure economics and bringing insulation measure activity in line with the change in market prices for the remainder of 2010.

Appliance and lighting activity also saw steady increases during 2010. Appliance measure participation increased 33 percent from steady growth in the ENERGY STAR appliance market and increased program visibility in the territory. Funded by the American Recovery and Reinvestment Act of 2009 the Idaho State Appliance Rebate program offered incentives on appliances. Customers could also receive incentives for the same appliances through the Home Energy Savings program. The combination of both incentives increased clothes washers by 30 percent and dishwashers by 26 percent for the Home Energy Saver Incentive program over the prior year. A program representative dedicated to field visits to local retailers and contractors made an increasing number of trips in 2010, giving the program a more consistent presence in the region.

CFL lighting activity saw a 20 percent increase in bulb sales by focusing on smaller and mid-level retailers like Family Dollar, Mickelsons and independently owned True Value Hardware stores who previously had not been involved in the program. By improving relationships with retailers the program was able to maximize available products under Idaho's specific tariff structure. In 2009, there were 19 products by the close of 2010, there were 40.

Representatives attended the Eastern Idaho Fair in September 2010 to promote program services and incentives, and provide general awareness of high efficiency equipment, lighting and weatherization options. The Eastern Idaho Fair attracts upwards of 210,000 people across 16 eastern Idaho counties. This is the largest outreach event the program attends.

Cost Effectiveness

The program was cost effective from all perspectives except the Ratepayer Impact Test. Appendix 1 provides detailed inputs used in the cost effectiveness analysis of this program.

Program Evaluation

Refer to the Program Evaluation in the 2010 Performance and Activities section of this report for evaluation activities related to this program.

Plans for 2011

The Home Energy Saver Incentive program is implementing a localized marketing strategy to increase awareness and participation. This strategy includes: attend more community events, provide more training and support for HVAC and weatherization contractors, visiting retail partners to provide additional training support, and marketing materials. Partnerships with other state and utility programs, trade associations and government offices will also be explored.

During 2011, the Company plans to make modifications to the Home Energy Saver Incentive program including changes to lighting, appliances, weatherization, heating and cooling measures. The proposed changes are designed to improve program performance, enhance participation and align with current codes and standards, and revise incentive levels to be more competitive with other utilities in the region.

See ya later, refrigerator® (Schedule 117)

The Residential Refrigerator Recycling Program (Schedule 117) is available to Idaho residential customers through a Company contracted third-party program administrator. Older refrigerators and freezers which are less efficient, yet operational, are taken out of use permanently and recycled in an environmentally responsible manner. The program's objective is to permanently retire these older and less efficient refrigerators and freezers from the market and recycle the units in order to avoid their re-entry or resale on the secondary appliance market. Program awareness is generated through mass media advertising channels as well as Company communications such as the program's web site, bill stuffers, and customer newsletters. In addition to free pick-up and a nominal cash incentive, participants receive an energy efficiency packet consisting of ENERGY STAR®-certified compact fluorescent light bulbs, a refrigerator/freezer thermometer, and energy education materials.

A summary of the program results for 2010 are provided in the table below.

Table 9: See ya later, refrigerator® Program Performance

2010 See ya later, refrigerator® Program Performance					
kWh Savings 2010 (Gross - At Gen)			1,138,658		
kWh Savings 2010 (Gross - At Site)			1,035,567		
Expenditures			$ 165,801		
Incentives Paid			$ 23,640		
	PTRC	TRC	UCT	RIM	PCT
Program Cost Effectiveness	1.268	1.153	1.080	0.455	19.148
Levelized Cost ($/kWh)	0.0551	0.0551	0.0589		
Lifecycle Revenue Impact ($/kWh)	$ 0.000072041				

Details of 2010 measure level participation and savings are provided on the following table:

Table 10: See ya later, refrigerator® Results

Refrigerator Recycling Measure	Unit Count	Per Unit Savings (kWh/Yr)	Gross Savings (kWh/Yr)
Refrigerator	629	1,149	722,721
Freezer	159	1,590	252,825
Total Units Recycled	**788**		**975,546**
Energy Savings Kits	741	81	60,021
		Total (At Site)	**1,035,567**
		Total (At Generation)	**1,138,658**

Major Trends and Activities

While program participation for 2010 increased by 9 percent as compared to 2009, program expenditures increased 53 percent over the same period. The increase in program expenditures were primarily driven by the multi-year process and impact evaluations completed in 2010.

A direct mail postcard with a refrigerator magnet intended to increase customer program awareness and provide a lasting call to action was mailed to 30,000 Idaho customers from the highest performing zip codes in previous years, generating a year-end increase in activity.

Environmental Attributes

In terms of the impact of the program on the environment, processing the 788 units resulted in the recycling of more than 100 thousand pounds of metal, 20 thousand pounds of plastics, half a ton of tempered glass and the capture, recovery or destruction of more than 1,000 lbs of ozone depleting chlorofluorocarbons (CFC) and hydrofluorocarbons (HFC), commonly used as refrigerants. The carbon dioxide ($CO2$) and carbon dioxide equivalent ($CO2e$) avoided from the atmosphere was equal to 6,500 tons.

Cost Effectiveness

The 2010 See ya later, refrigerator® program was cost effective from all perspectives except the Ratepayer Impact Test. Appendix 1 provides detailed inputs used in the cost effectiveness analysis of this program. .

Program Evaluation

Refer to the Program Evaluation heading in the 2010 Performance and Activities section of this report for evaluation activities related to this program.

Plans for 2011

Several new program design features will help increase program participation starting in spring of 2011. Based on successful direct mail campaigns in 2010 more direct mail will be used in 2011. Direct mail postcards with a refrigerator magnet advertising the program will be sent out in two different batches in 2011. The program is working with Sears, Best Buy, Lowe's and other appliance retailers in Idaho to allow customers to have new units delivered and the old units picked up at the same time. This allows home owners to schedule only one appointment for the delivery of their new appliance and the pickup of their old one. Cross program coordination with the Home Energy Savings program will improve coordination with retailers on ENERGY STAR appliances, making it more convenient for customers to participate in the See ya later, refrigerator® program.

Low Income Weatherization (Schedule 21)

The Low Income Weatherization Services program (Schedule 21) is available through a partnership with Eastern Idaho Community Action Partnership (EICAP) in Idaho Falls and South Eastern Idaho Community Action Agency (SEICAA) in Pocatello. These partnerships allow for leveraging of Company funding with federal grants available to EICAP and SEICAA, increasing the number of homes served. Rocky Mountain Power's funding in 2010 provided rebates that covered 75 percent of the cost of approved energy efficiency measures.

Income eligible households receive energy efficiency services at no cost. Participants can be either homeowners or renters residing in single-family homes, manufactured homes and apartments.

Table 9 summarizes the program results for 2010. The reported energy savings is based on measured savings documented in an analysis dated August 30, 2006 completed by Quantec/Cadmus. Program expenditures totaled $133,673. Funds received by the agency from other sources (state or federal funding) are not included.

Rocky Mountain Power's program provided funding towards the weatherization of 43 qualifying homes in 2010 with an average program cost per home of $3,109.

Table 11: Low Income Weatherization Performance

Low Income Weatherization Performance - Idaho		
kWh/Yr Savings (Gross at Site)		71,346
kWh/Yr Savings (Gross at Gen)		78,448
Expenditures - Total	$	133,673
Participation - Total # of Completed/Treated Homes		43
Number of Homes Receiving Specific Measures		
Ceiling Insulation		17
Floor Insulation		6
Wall Insulation		3
Replacement Windows		16
Storm Windows		1
Duct Insulation/Sealing		5
Insulated Doors		14
Attic Ventilation		14
Infiltration		19
Water Pipe Insulation and Sealing		31
Water Heater Repair/Replacement		4
Furnace Repair/Tune-up/Filters		7
Furnace Replacement		3
Compact Fluorescent Light bulbs (CFL)		43
Health & Safety Measure		15

	PTRC	TRC	UCT	RIM	PCT
Program Cost Effectiveness	0.730	0.664	0.664	0.385	NA
Levelized Cost ($/kWh)	0.1330	0.1330	0.1330		
Lifecycle Revenue Impact ($/kWh)	$0.000015127				

Major Trends and Activities

Participation during 2010 decreased by 62 percent compared to 2009. Participation numbers can be greatly affected by the timing of when agency invoices are received and processed making completions in a year seem significantly high or low. Program savings decreased 63 percent and expenditure increased by 32 percent in 2010 compared to 2009. Expenditures were affected by a $7,500 payment for kits that will be used in the agencies energy education program, and costs related to a program evaluation.

Cost Effectiveness

An evaluation of Low Income Weatherization Services Optional for Income Qualifying Customers program was completed in 2011 by a third party administrator based on program activities in 2007 through 2009.

The program evaluation performed includes the review of processes and impacts. It provides kWh savings determined through billing analyses, as well as estimates for non-energy benefits. The Company's portfolio of energy efficiency programs is cost effective, but the evaluation indicates that Schedule 21 is not cost-effective from the Total Resource Cost (TRC), Utility Cost (UCT) or Ratepayer Impact (RIM) perspectives unless non-energy benefits are included.

The Company recognizes the importance of our Low Income Weatherization Program and the benefit to our customers by reducing kWh usage and helping to make participant's bills more affordable, as well as increasing their comfort. However, as described in the Low-Income Weatherization program evaluation, due to many factors the program is not cost-effective. To this end, the Company has a pending application requesting the Commission acknowledge the program as an acceptable part of the Company's program portfolio, and find that it should continue.

Program Evaluation

Refer to the Program Evaluation heading in the 2010 Performance and Activities section of this report for evaluation activities related to this program.

Plans for 2011

The Low Income Weatherization program was revised on December 28, 2010. Per an order by the Commission, Rocky Mountain Power's reimbursement on eligible measures increased from 75% to 85% and the maximum annual reimbursement to our partnering agencies increased from $150,000 to $300,000. With these changes, we anticipate an increase in homes treated. The Company believes that the cost-effectiveness will be further eroded with the recent increase to cost sharing requirements, therefore the Company has a pending application requesting the Idaho Public Utilities Commission remove any future obligation for program evaluations.

Non-Residential Energy Efficiency Programs and Activity

Energy FinAnswer (Schedule 125)

The Energy FinAnswer program is offered to commercial (buildings 20,000 square feet and larger) and industrial customers. The program provides Company-funded energy engineering, incentives of $0.12 per kWh of first year energy savings and $50 per kW of average monthly demand savings up to a cap of 50 percent of the approved project cost. The program is designed to target comprehensive projects requiring project specific energy savings analysis and operates as a complement to the more streamlined FinAnswer Express program. In addition to customer incentives, the program provides design team honorariums (a finder fee for new projects) and design team incentives for new construction projects exceeding current Idaho energy code by at least 10 percent.

A summary of the program results are provided in the table below:

Table 12: Energy FinAnswer Program Performance

kWh/Yr Savings 2010 (Gross - At Gen)		1,609,040			
kWh/Yr Savings 2010 (Gross - At Site)		1,475,439			
Expenditures		$ 369,186			
Incentives Paid		$ 107,598			
	PTRC	TRC	UCT	RIM	PCT
Program Cost Effectiveness	2.405	2.187	2.546	0.984	4.121
Levelized Cost ($/kWh)	0.0410	0.0410	0.0352		
Lifecycle Revenue Impact ($/kWh)	$ 0.0000008314				

Details of 2010 savings by type of measure are provided on the following table:

Table 13: Energy FinAnswer by Measure Type

Energy FinAnswer kWh/Yr Savings (at site) by Measure Type		
Compressed Air	406,336	28%
Lighting	26,665	2%
Motors	647,994	44%
Refrigeration	394,444	27%
	1,475,439	

Major Trends and Activities

A total of ten Energy FinAnswer projects were completed in 2010 compared to eight in 2009. Program specific energy savings and expenditures remained constant during 2010 compared to 2009. The Company continues to market the program through its Customer and Community Managers and network of trade allies in concert with the FinAnswer Express program.

Cost Effectiveness

The 2010 Energy FinAnswer program was cost effective from all perspectives except the Ratepayer Impact Test. Appendix 1 provides detailed inputs used in the cost effectiveness analysis of this program.

Program Evaluation

Refer to the Program Evaluation heading in the 2010 Performance and Activities section of this report for evaluation activities related to this program.

Plans for 2011

Continue to monitor actual and forecasted participation and assess the potential impacts of program modifications similar to those implemented in other markets.
The Company is investigating possible adjustments to program incentives, adjusting the project cost cap and introducing a program option allowing for savings driven proportionate co-funding of energy project managers at a customer facility site to assist in the completion of energy efficiency projects.

FinAnswer Express (Schedule 115)

The FinAnswer Express program (Schedule 115) is available to Idaho business customers excluding those served on Schedule 10, which are eligible for program services through the Agricultural Energy Services program. The FinAnswer Express program is available to help customers improve the efficiency of their new or replacement lighting, HVAC, motors, building envelope and other equipment by providing prescriptive or pre-defined incentives for the most common efficiency measures listed in the program incentive tables. The program also includes custom incentives and technical analysis services for measures not listed in the program incentive tables that improve electric energy efficiency. The program is designed to operate in conjunction with the Energy FinAnswer program. Although incentives available vary, the program provides incentives for both new construction and retrofit projects.

The program is primarily marketed through local trade allies who receive support from Company provided sales and training team. The lists of participating vendors posted on the Company website include 18 lighting, 30 HVAC, 24 motor, and 3 other equipment trade allies.

A summary of the program results are provided in the table below:

Table 14: FinAnswer Express Program

kWh/Yr Savings 2010 (Gross - At Gen)		3,864,185			
kWh/Yr Savings 2010 (Gross - At Site)		3,534,752			
Expenditures		$ 620,490			
Incentives Paid		$ 293,098			
	PTRC	TRC	UCT	RIM	PCT
Program Cost Effectiveness	2.188	1.989	3.256	0.862	2.929
Levelized Cost ($/kWh)	0.0431	0.0431	0.0264		
Lifecycle Revenue Impact ($/kWh)	$ 0.000085588				

Details of 2010 savings by type of measure are provided on the following table:

Table 15: FinAnswer Express by Measure Type

FinAnswer Express kWh/Yr Savings (at site) by Measure Type		
Lighting	1,147,600	32%
Non-Lighting	2,387,152	68%
	3,534,752	

Major Trends and Activities

During 2010, savings were significantly higher (322%) than in 2009 primarily a result of the completion of several new construction projects occurring in the education sector. The new construction projects were primarily driven by one customer undergoing an expansion phase, 2010 savings levels will likely not be repeated in 2011.

On May 6, 2010, Rocky Mountain Power provided lighting and mechanical/nonlighting program training in combination with the Northwest regional trade ally network lighting training in Idaho Falls, 60 individuals attended.

Cost Effectiveness

The program was cost effective from all perspectives except the Ratepayer Impact Test. Appendix 1 provides detailed inputs and assumptions used in the cost effectiveness analysis of this program.

Program Evaluation

Refer to the Program Evaluation heading in the 2010 Performance and Activities section of this report for evaluation activities related to this program.

Plans for 2011

The Company plans to file program changes in 2011 to add new measure categories such as dairy farm, small compressed air, appliances, and food service to the program and also update existing measures.

The Company plans to provide marketing and trade ally outreach to target customers with T12 fluorescent lighting to provide information on changes in federal lighting standards coming in 2012 and the limited time opportunity to upgrade to higher efficient lighting before the standards take effect while current incentives are available.

Agricultural Energy Services (Schedule 155)

Agricultural Energy Services, marketed as Irrigation Energy Savers (Schedule 155), was available in 2010 to Idaho irrigation customers taking retail service on Schedule 10 through a Company contracted third-party program administrator. The program design is intended to be the energy efficiency complement to the Irrigation Load Control programs offered under Schedules 72 & 72A. The 2010 program included the following customer service and measure components:

- Equipment Exchange – Provides new standard brass sprinkler nozzles, gaskets, and drains to replace worn equipment on hand lines, wheel lines and solid set sprinklers systems.
- Pivot and Linear Equipment Upgrades – Incentives are provided for certain pivot and linear system measures including sprinkler packages, pressure regulators, and drains. The list of prescriptive incentives is not designed to be exhaustive and other pivot measures are eligible for incentives if energy savings can be calculated and the customer incurs costs to make the changes.
- System Consultation – This service provides a simple site specific audit of a customer's irrigation system to promote irrigation water management and identify energy savings opportunities. This consultation provides information prior to a full pump test.
- Pump Testing – The pump test includes directly measuring pump lift, flow, electrical demand, and system pressures and is performed after the pump has been screened and the owner's financial investment criteria understood.
- System Analysis – The program provides energy engineering to help growers quantify the costs and savings of their system efficiency upgrades. Often these upgrade decisions are made in conjunction with operational production change considerations impacting a growers equipment needs. Incentives are based on a standard formula tied to costs and first year energy savings.

A summary of the program results for 2010 are provided in the table below.

Table 16: Agricultural Energy Services Program Performance

2010 Agricultural Energy Services Program Performance					
kWh/Yr Savings 2010 (Gross - At Gen)		2,742,918			
kWh/Yr Savings 2010 (Gross - At Site)		2,515,169			
Expenditures		$ 637,009			
Incentives Paid		$ 250,924			
	PTRC	TRC	UCT	RIM	PCT
Program Cost Effectiveness	1.172	1.066	1.332	0.751	1.813
Levelized Cost ($/kWh)	0.0825	0.0825	0.0660		
Lifecycle Revenue Impact ($/kWh)	$0.000124309				

Details of 2010 savings by type of measure are provided on the following table:

Table 17: Agricultural Energy Savers by Measure Type

Agricultural Energy Savers kWh/Yr Savings by Measure Type (at Site)		
Equipment Exchange & Pivot/Linear Upgrade	1,658,488	66%
System Design	856,681	34%
	2,515,169	

Major Trends and Activities

The 2010 savings and expenses were 37 percent and 21 percent lower compared to 2009 program savings and expenditures.

During 2010 90 site visits were completed to obtain system information used in either a system consultation or an energy analysis evaluation as a part of the Agricultural Energy Services Program. During the same year, 19 post installation inspections were completed to verify project installation and energy savings.

The following outreach and event activities were completed for the program in 2010:

- Provided a one hour presentations at the Golden West Irrigation Company pivot school on program components available and potential savings for irrigation pump VFDs on February 23rd and 24th, 2010.
- Provided a one hour presentation on program components available and potential savings for irrigation pump VFDs and met with customers at the Rain For Rent customer appreciation day in Idaho Falls on February 25th, 2010.
- Operated a booth at the Valley Implement customer appreciation day in Preston on February 25th, 2010.
- Provided the updated program manual and 2010 program applications to all of the participating dealers and followed up with phone calls to discuss program updates.

Cost Effectiveness

The program was cost effective from all perspectives except the Ratepayer Impact Test. Appendix 1 provides detailed inputs and assumptions used in the cost effectiveness analysis of this program.

The last program and impact evaluation determined energy savings at a precision of ±551 percent for the equipment exchange and pivot/linear upgrade. The system design category was calculated at ±86 percent precision, both reported at a 90 percent confidence interval. Due to the wide range of savings calculations, 2009 realization rate of 1.00 was used in 2010 cost effectiveness tests.

Program Evaluation

Refer to the Program Evaluation heading in the 2010 Performance and Activities section of this report for evaluation activities related to this program.

Plans for 2011

The results of the program evaluation were inconclusive. The program results will be reviewed with the stakeholders to determine if the program should be modified or suspended.

Market Transformation - Northwest Energy Efficiency Alliance

The contract with the Northwest Energy Efficiency Alliance was not renewed in 2010 for the 2010-2014 funding cycle. The company is currently evaluating the benefits and costs associated with this program to ensure Rocky Mountain Power customers in southeastern Idaho are beneficiaries of the alliance activities.

Summary of 2010 Results:

Table 18: Revenues (Schedule 191) by Customer Type

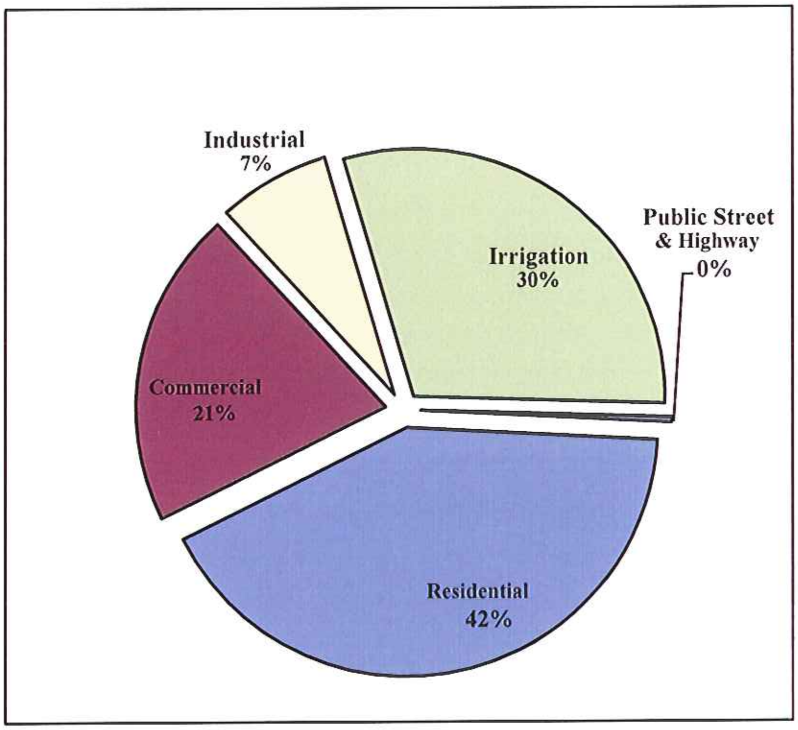
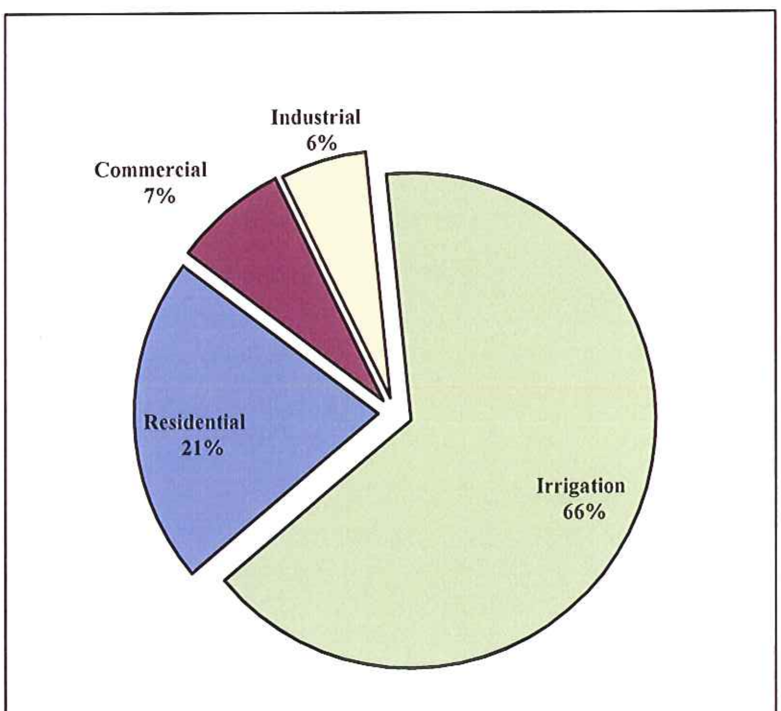
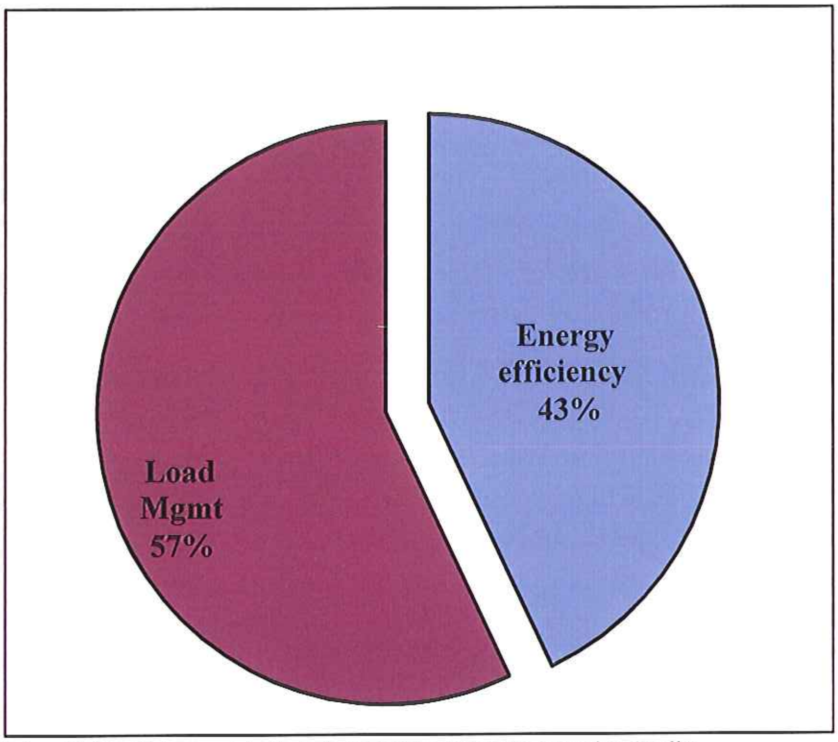


Table 19: Expenditures (Schedule 191) by Customer Type



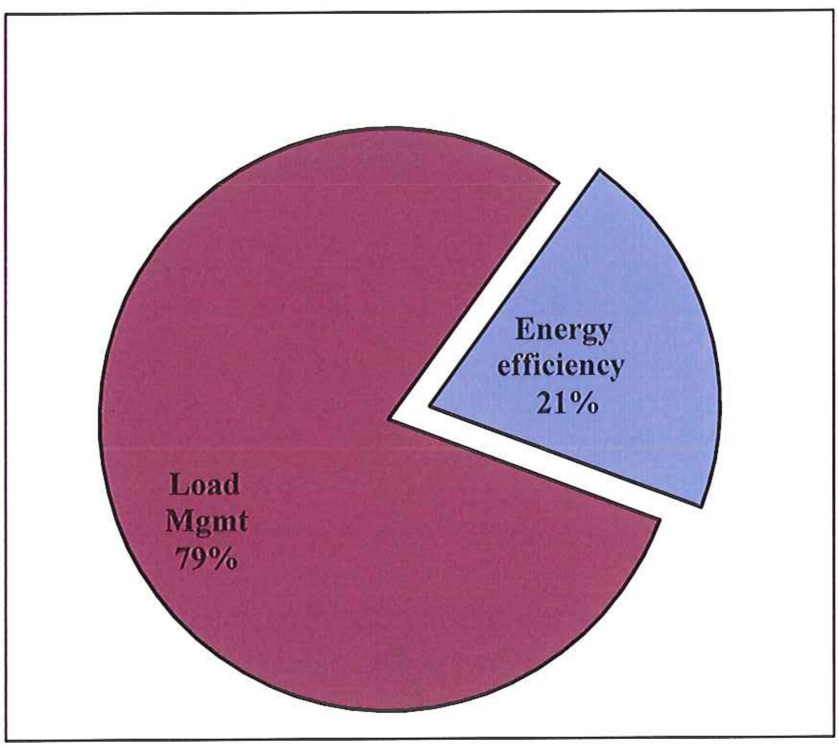
(Note – Table 17 does not include Irrigation Load Control Service Credits

Table 20: Expenditures (Schedule 191) by Type of Program



(Note – Table 18 does not include Irrigation Load Control Service Credits

Table 21: Total expenditures by Type of Program



(Note – Table 19 includes Schedule 191 expenditures and Irrigation Load Control Service Credits

Table 22: Energy Efficiency Expenditures by Customer Type

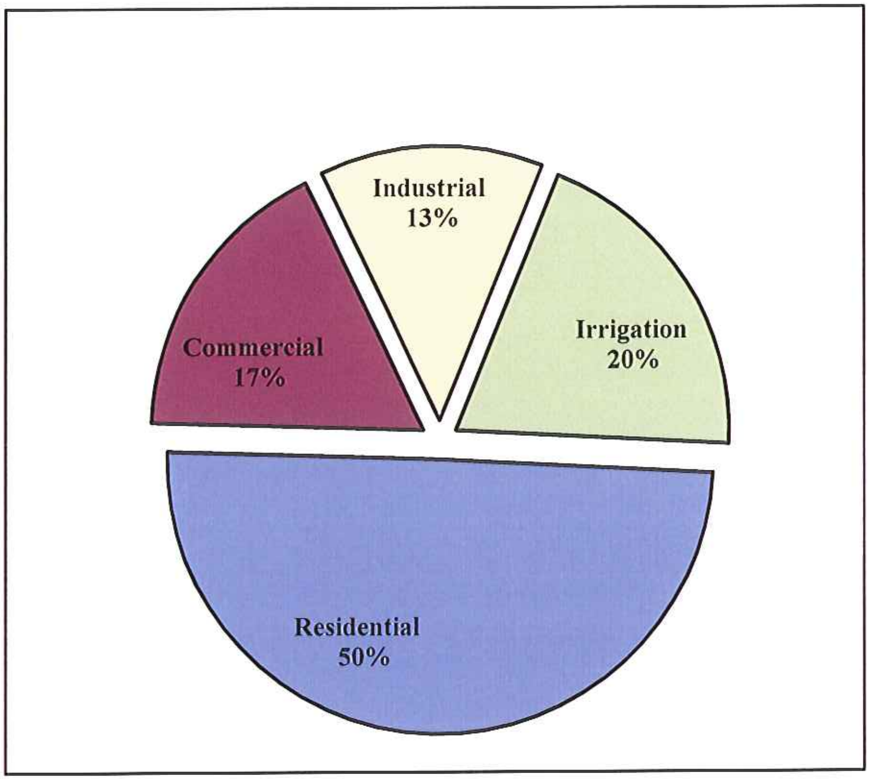
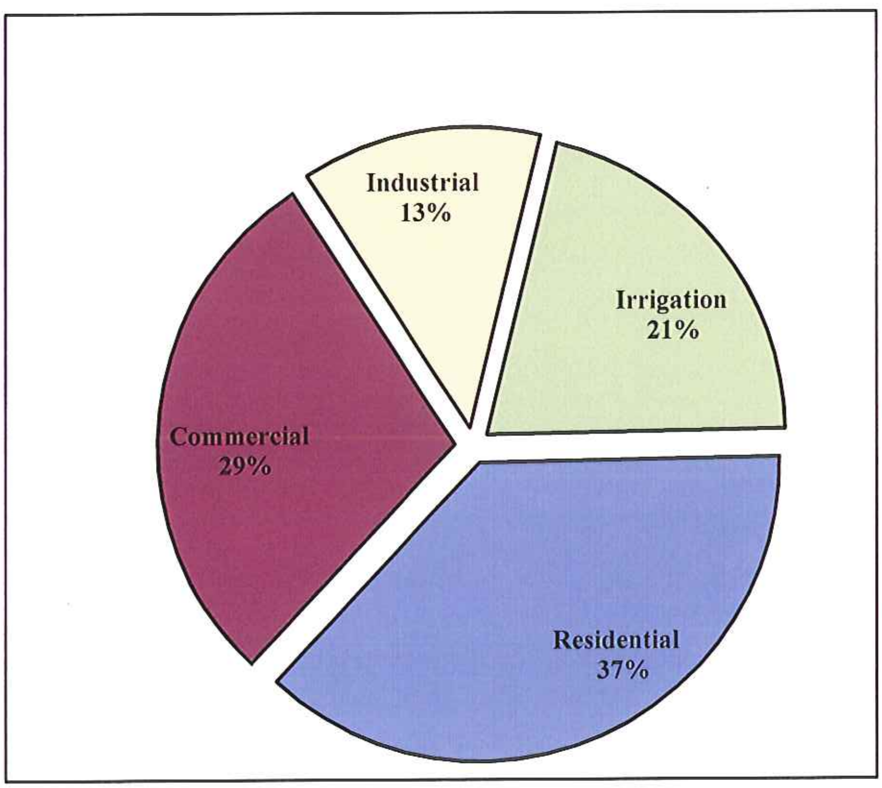


Table 23: Energy Efficiency Results by Customer Type



Balancing Account Summary

Energy efficiency and peak reduction activities are funded by revenue collected through Schedule 191, Customer Efficiency Services Rate on customer bills. Expenses for energy efficiency and peak reduction programs are charged as incurred and booked to the balancing account. The energy efficiency and peak reduction balancing account activity for 2010 is outlined in the table below.

Table 24: Balancing Account Activity (Schedule 191)

	Monthly Program Cost - Fixed Assets	Rate Recovery	Carrying Charge	Accumulated Balance
			Balance as of 12/31/09	$ 2,238,820
January	$ 287,808.96	$ (369,551.91)	$ 1,832.00	$ 2,158,909.32
February	$ 455,659.05	$ (331,048.08)	$ 1,851.00	$ 2,285,371.29
March	$ 698,743.75	$ (305,425.78)	$ 2,068.00	$ 2,680,757.26
April	$ 439,621.74	$ (281,236.32)	$ 2,300.00	$ 2,841,442.68
May	$ 1,074,442.77	$ (345,158.17)	$ 2,672.00	$ 3,573,399.28
June	$ 794,231.51	$ (461,618.58)	$ 3,116.00	$ 3,909,128.21
July	$ 602,679.49	$ (855,785.03)	$ 3,152.00	$ 3,659,174.67
August	$ 942,866.52	$ (958,865.47)	$ 3,043.00	$ 3,646,218.72
September	$ 429,505.50	$ (668,751.45)	$ 2,939.00	$ 3,409,911.77
October	$ 598,206.77	$ (494,519.47)	$ 2,885.00	$ 3,516,484.07
November	$ 381,355.70	$ (412,828.01)	$ 2,917.00	$ 3,487,928.76
December	$ 809,904.62	$ (455,044.85)	$ 3,054.00	**$ 3,845,842.53**
2010 totals	**$ 7,515,026.38**	**$ (5,939,833.12)**	**$ 31,829.00**	

Column Explanations:

Monthly Program Costs – Fixed Assets: Monthly expenditures for all energy efficiency and peak reduction program activities.

Rate Recovery: Revenue collected through Schedule 191, Customer Efficiency Service Rate.

Carrying Charge: Monthly "interest" charge based on "Accumulated Balance" of the account. The current "interest rate" for the Accumulated Balance is 1 percent per year.

Accumulated Balance: Current balance of the account. A running total of account activities. If more is collected in "Revenue" than is spent for a given month, the "Accumulated Balance" will be decreased by the net amount. A negative accumulative balance means cumulative revenue exceeds cumulative expenditures; positive accumulative balance means cumulative expenditures exceed cumulative revenue.

At the beginning of 2010, the unfunded balance was approximately $2.2 million and increased by approximately $1,607,000 during 2010. The unfunded balance at the end of 2010 is $3.846 million.

Cost Effectiveness:

Introduction

The cost effectiveness of individual programs operated by the Company for 2010 are calculated using actual expenditures and reported savings. Cost-effectiveness is provided at the individual program, load management portfolio, residential energy efficiency portfolio, non-residential energy efficiency portfolio, combined energy efficiency portfolio, and overall energy efficiency and peak reduction program portfolio levels. Deemed savings estimates where applicable were the same as those used in the planning estimates, unless more recent estimates were available from evaluations.

Energy savings shown in this report are gross savings and the impact of line losses is indicated with an at "site" or at "generation" designation. Line losses are based on the Company's 2007 line loss study. Net-to-gross assumptions are consistent with planning estimates. The energy savings attributed to each program are shaped according to specific end-use savings (the hourly calculation of when energy is used for the various end-use measures from which the savings are derived). Program costs and the value of the energy savings are then compared on a present value basis with the Company's 2008 Integrated Resource Plan (IRP) calculated decrement values for demand-side resource savings and avoided capacity investments. The energy efficiency resource decrement values are fully shaped to represent the 8,760 hourly values that exist within a calendar year. By matching the hourly savings with the hourly avoided costs, both energy and capacity impacts of energy efficiency savings are recognized.

The cost/benefit analysis of the load management programs are based on the avoided value of peak or capacity investments. For purposes of calculating program cost-effectiveness no energy savings are included for the load management programs, only a shift of when the energy is used away from the peak load hours. The five California Standard Practice Manual cost effectiveness tests were utilized in the cost benefit analysis for both energy efficiency and load management programs. Further details are available in Appendix 1.

Key Assumptions for Cost Effectiveness Calculations:

Cost Effectiveness calculations for programs and measures (or measure groups) within each program will be detailed in the tables in Appendix 1.

Global Assumptions used in all cost effectiveness calculations include:

Assumption	Value	Source
Discount Rate	7.40%	2008 IRP
Line Losses (Idaho Specific)		
Residential	9.955%	2007 MAC Line Loss Study
Commercial	9.326%	2007 MAC Line Loss Study
Industrial	9.055%	2007 MAC Line Loss Study

Key elements that go into the cost effectiveness calculation for each program include:

- KW/kWh Savings Gross
- Administrative Expenses
- Incentives Paid
- Total Utility costs – including administration and evaluation
- Gross Customer Costs
- Net To Gross Ratio
- Measure Life
- IRP Decrement Value

Please reference Appendix 1, Cost Effectiveness 2010 Idaho Energy Efficiency and Peak Reduction Annual Report for additional information on the key assumptions and inputs for cost effectiveness calculations for each program.

Appendices:

Appendix 1 – Cost Effectiveness 2010 Idaho Energy Efficiency and Peak Reduction Annual Report

Appendix 2 – *2010 Idaho Load Control Program Quantitative Analysis*

Appendix 3 – The Cadmus Group's Evaluation Report on Rocky Mountain Power's Irrigation Load Control Credit Rider Program

APPENDIX 1

ROCKY MOUNTAIN POWER
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Appendix 1

Cost Effectiveness
2010 Idaho Energy Efficiency and Peak Reduction Annual Report

Rocky Mountain Power

Portfolio and Sector Level Cost Effectiveness

The overall energy efficiency and peak reduction portfolio and component sectors were all cost effective on a Total Resource Cost and Utility Cost basis. As expected, only the Load Control component generated a Ratepayer Impact Test of greater than 1.0.

The following table provides the overall portfolio and sector results of all five cost effectiveness tests.

2010 Portfolio and Sector Cost Effectiveness Summary

	Cost Effectiveness Test				
	PTRC	TRC	UCT	RIM	PCT
2010 Total Portfolio including Load Control	2.613	2.376	1.246	0.913	7.010
2010 Total Portfolio excluding Load Control	1.978	1.798	2.175	0.788	3.298
2010 C&I Energy Efficiency Portfolio	1.869	1.699	2.342	0.860	2.726
2010 Residential Energy Efficiency Portfolio	2.124	1.931	2.007	0.716	4.090
2010 Irrigation Load Control	3.190	2.900	1.000	1.000	NA

Portfolio and Segment Level Cost Effectiveness Summaries:

The cost effectiveness results for the portfolio level and segment level are aggregations of the costs and benefits from the component programs. The inputs and assumptions that support these results are contained in the program level cost effectiveness results.

2010 Total Portfolio including Load Control

	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost Ratio
Total Resource Cost Test (PTRC) + Conservation Adder	NA	$8,192,802	$21,409,860	$13,217,058	2.613
Total Resource Cost Test (TRC) No Adder	NA	$8,192,802	$19,463,509	$11,270,707	2.376
Utility Cost Test (UCT)	NA	$15,615,246	$19,463,509	$3,848,263	1.246
Rate Impact Test (RIM)		$21,306,792	$19,463,509	($1,843,283)	0.913
Participant Cost Test (PCT)		$2,181,898	$15,295,888	$13,113,990	7.010
Lifecycle Revenue Impacts ($/kWh)				NA	

2010 Total Portfolio excluding Load Control

	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost Ratio
Total Resource Cost Test (PTRC) + Conservation Adder	0.0521	$3,909,409	$7,731,899	$3,822,490	1.978
Total Resource Cost Test (TRC) No Adder	0.0521	$3,909,409	$7,028,999	$3,119,590	1.798
Utility Cost Test (UCT)	0.0431	$3,231,172	$7,028,999	$3,797,827	2.175
Rate Impact Test (RIM)		$8,922,718	$7,028,999	($1,893,719)	0.788
Participant Cost Test (PCT)		$2,181,898	$7,195,207	$5,013,309	3.298
Lifecycle Revenue Impacts ($/kWh)				$0.0000417229	

2010 C&I Energy Efficiency Portfolio

	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost Ratio
Total Resource Cost Test (PTRC) + Conservation Adder	0.0513	$2,242,052	$4,190,015	$1,947,963	1.869
Total Resource Cost Test (TRC) No Adder	0.0513	$2,242,052	$3,809,104	$1,567,053	1.699
Utility Cost Test (UCT)	0.0373	$1,626,686	$3,809,104	$2,182,418	2.342
Rate Impact Test (RIM)		$4,428,646	$3,809,104	($619,541)	0.860
Participant Cost Test (PCT)		$1,266,986	$3,453,580	$2,186,594	2.726
Lifecycle Revenue Impacts ($/kWh)				$0.0000256276	

2010 Residential Energy Efficiency Portfolio

	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost Ratio
Total Resource Cost Test (PTRC) + Conservation Adder	0.0532	$1,667,357	$3,541,885	$1,874,527	2.124
Total Resource Cost Test (TRC) No Adder	0.0532	$1,667,357	$3,219,895	$1,552,538	1.931
Utility Cost Test (UCT)	0.0512	$1,604,486	$3,219,895	$1,615,409	2.007
Rate Impact Test (RIM)		$4,494,073	$3,219,895	($1,274,178)	0.716
Participant Cost Test (PCT)		$914,912	$3,741,628	$2,826,715	4.090
Lifecycle Revenue Impacts ($/kWh)				$0.0000600654	

2010 Irrigation Load Control

All Measures					
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost Ratio
Total Resource Cost Test (PTRC) + Conservation Adder		$4,283,393	$13,677,960	$9,394,567	3.19
Total Resource Cost Test (TRC) No Adder		$4,283,393	$12,434,509	$8,151,116	2.90
Utility Cost Test (UCT)		$12,384,074	$12,434,509	$50,435	1.00
Rate Impact Test (RIM)		$12,384,074	$12,434,509	$50,435	1.00
Participant Cost Test (PCT)		$0	$8,100,681	$8,100,681	NA
Lifecycle Revenue Impacts ($/kWh)					

Program Level Cost Effectiveness

Irrigation Load Control Program – Schedules 72 and 72A

The following tables outline the primary inputs and assumptions utilized in the cost effectiveness calculations for the program.

Program Inputs - Irrigation Load Control	Value	Source and Notes
Average kW Dispatched during irrigation season (At Site)	156,000	Impact Evaluation -Cadmus 2010
Average kW Dispatched during irrigation season (At Gen)	170,126	Calculation - Gross up for Line Losses at 9.06%
Benefit Value of Dispatched kW (At Gen)	$ 73.09	2010 Value as determined by agreed upon Valuation Methodology - 2008 IRP
Benefit Value = Avg kW Dispatched multiplied by $73.09	$ 12,434,495	Calculation ($73.09 $/kW * 170,126 kW-Yr)
Program Management and Administration Costs	$ 4,283,393	Annual costs 2010
Incentives	$ 8,100,681	Annual costs 2010
Total Utility Costs	$ 12,384,074	Annual costs 2010
Total Participant Costs	NA	There are no direct participant costs for the program.
Net To Gross Ratio	1.00	Assume 1.0 Net To Gross
Measure Life (Years)	10	Benefit value is NPV of 10 year benfits from avoided generation and market purchases.

All Measures	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost Ratio
Total Resource Cost Test (PTRC) + Conservation Adder		$4,283,393	$13,677,960	$9,394,567	3.19
Total Resource Cost Test (TRC) No Adder		$4,283,393	$12,434,509	$8,151,116	2.90
Utility Cost Test (UCT)		$12,384,074	$12,434,509	$50,435	1.00
Rate Impact Test (RIM)		$12,384,074	$12,434,509	$50,435	1.00
Participant Cost Test (PCT)		$0	$8,100,681	$8,100,681	NA
Lifecycle Revenue Impacts ($/kWh)					
Discounted Participant Payback (years)					

Additional information regarding major trends and activities, program evaluations, and plans for 2011 for the irrigation load control program are available in the 2010 seasonal report *2010 Idaho Irrigation Load Control Quantitative Review* (Appendix 1) dated January 7, 2011.

Home Energy Savings Program – Schedule 118

The following tables outline the primary inputs and assumptions utilized in the cost effectiveness calculations for the program.

Program Inputs - Home Energy Savings		
Gross kWh/Year Savings (at Site)	3,086,839	Annual results 2010 (Gross at Site)
Program Management and Administration Costs	$ 476,613	Annual costs 2010
Incentives	$ 828,401	Annual costs 2010
Total Utility Costs	$ 1,305,014	Annual costs 2010
Total Participant Costs	$ 1,099,720	Deemed costs per unit * unit participation. Deemed costs per unit is from a variety of sources, including Regional Technical Forum, Energy Star and analysis of invoices submitted with incentive applications Developed and maintained by program administrator - PECI.
Net To Gross Ratio	0.82	Evaluation Home Energy Savings Program, Cadmus 2010
Measure Life		Utilize measure specific life

All Measures				AC: IRP 46% LF Decrement	
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost Ratio
Total Resource Cost Test (PTRC) + Conservation Adder	0.0501	$1,378,383	$3,247,361	$1,868,978	2.356
Total Resource Cost Test (TRC) No Adder	0.0501	$1,378,383	$2,952,147	$1,573,763	2.142
Utility Cost Test (UCT)	0.0475	$1,305,013	$2,952,147	$1,647,134	2.262
Rate Impact Test (RIM)		$3,869,975	$2,952,147	($917,829)	0.763
Participant Cost Test (PCT)		$901,771	$3,393,363	$2,491,592	3.763
Lifecycle Revenue Impacts ($/kWh)				$0.0001034536	
Discounted Participant Payback (ye				6.00	

Measure Group Inputs and Assumptions:

Lighting (Includes CFLs, Fixtures and Ceiling Fans)	Value	Source and Notes
Gross kWh/Year Savings (at Site)	888,561	Annual results 2010 (Gross at Site) based on measure level savings from Energy Star savings calculator 2008 and RTF PTR Software 2007
Program Management and Administration Costs	$ 15,991	Allocated percentage (based on kWh contribution) of non -incentive costs for 2010.
Incentives	$ 30,199	Annual costs 2010
Total Utility Costs	$ 46,191	Annual costs 2010
Total Participant Costs	$ 90,204	Deemed based on RTF estimates developed and maintained by program administrator - PECI.
Net To Gross Ratio	0.82	Evaluation Home Energy Savings Program, Cadmus 2010
Measure Life (Years)	5	Conservative global planning estimate that recognizes trend toward conservative shorter measure lifes.
2008 IRP Decrement Load Shape		East Side Residential Lighting

Appliances (Clothes Washers, Dishwasher, Water Heater, Refrigerator)	Value	Source and Notes
Gross kWh/Year Savings (at Site)	404,366	Annual results 2010 (Gross at Site) based on measure level savings from RTF PTR Software 2007
Program Management and Administration Costs	$ 76,270	Allocated percentage (based on kWh contribution) of non -incentive costs for 2010.
Incentives	$ 151,920	Annual costs 2010
Total Utility Costs	$ 228,190	Annual costs 2010
Total Participant Costs	$ 370,723	Deemed based on RTF and Energy Star estimates developed and maintained by program administrator - PECI.
Net To Gross Ratio	0.82	Evaluation Home Energy Savings Program, Cadmus 2010
Measure Life (Years)	14	Conservative global planning estimate that recognizes trend toward conservative shorter measure lifes.
2008 IRP Decrement Load Shape		East Side Residential Whole House

Shell Measures (Insulation and Windows)	Value	Source and Notes
Gross kWh/Year Savings (at Site)	1,787,743	Annual results 2010 (Gross at Site) based on measure level inputs from RTF PTR Software Version 1.0, FY 2007 (10/1/2006 - 9/30/2007)+Cooling Coefficient-Research-Gary Smith-2006
Program Management and Administration Costs	$ 383,176	Allocated percentage (based on kWh contribution) of non -incentive costs for 2010.
Incentives	$ 621,307	Annual costs 2010
Total Utility Costs	$ 1,004,483	Annual costs 2010
Total Participant Costs	$ 589,694	Windows deemed based on RTF. Insulation is based on application analysis.
Net To Gross Ratio	0.82	Evaluation Home Energy Savings Program, Cadmus 2010
Measure Life (Years)	30	Conservative global planning estimate that recognizes trend toward conservative shorter measure lifes.
2008 IRP Decrement Load Shape		East Side Residential Whole House

HVAC (AC and Heat Pump Equipment, Tune ups, Proper Installations, Duct Sealing)	Value	Source and Notes
Gross kWh/Year Savings (at Site)	6,169	Annual results 2010 (Gross at Site) based on measure level inputs from Quantec Evaluation 2006, Research from Energy Trust of Oregon 2007, and RTF PTR Software Version 1.0 + Research by Gary Smith 2006.
Program Management and Administration Costs	$ 1,175	Allocated percentage (based on kWh contribution) of non -incentive costs for 2010.
Incentives	$ 24,975	Annual costs 2010
Total Utility Costs	$ 26,150	Annual costs 2010
Total Participant Costs	$ 49,100	Incremental costs for HVAC measures based on Utah cool cash program. Tune-ups & heat pumps - RTF. Duct sealing - PTCS/RTF. Developed and maintained by program administrator - PECI.
Net To Gross Ratio	0.82	Evaluation Home Energy Savings Program, Cadmus 2010
Measure Life (Years)	14	Conservative global planning estimate that recognizes trend toward conservative shorter measure lifes.
2008 IRP Decrement Load Shape		East Side Residential Cooling

Process and Impact Evaluation
Process and impact evaluations were completed during 2010. The Company during 2010 received process and impact evaluations for program years 2006 to 2008. Results of those evaluations are available at www.pacificorp.com/es/dsm/idaho.

In the future, the Company intends to complete process and impact evaluations on a two year cycle for each program in the energy efficiency and peak reduction portfolio. The timing and cycle of evaluations may vary based on maturity of the program, changes in the marketplace, changes in underlying codes and standards and the potential cost of evaluation.

Refrigerator Recycling (See ya later, refrigerator®) – Schedule 117

The following tables outline the primary inputs and assumptions utilized in the cost effectiveness calculations for the program.

Program Inputs - See ya later, refrigerator®			
Gross kWh/Year Savings (at Site)		1,035,567	Annual results 2010 (Gross at Site)
Program Management and Administration Costs	$	142,161	Annual costs 2010
Incentives	$	23,640	Annual costs 2010
Total Utility Costs	$	165,801	Annual costs 2010
Total Participant Costs		NA	There are no participant costs for this program.
Net To Gross Ratio			Utilize measure specific savings and Net To Gross
Measure Life (Years)			*Utilize measure specific life*

All Measures				AC: IRP 46% LF Decrement	
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost Ratio
Total Resource Cost Test (PTRC) + Conservation Adder	0.0551	$155,302	$196,938	$41,636	1.268
Total Resource Cost Test (TRC) No Adder	0.0551	$155,302	$179,035	$23,733	1.153
Utility Cost Test (UCT)	0.0589	$165,801	$179,035	$13,234	1.080
Rate Impact Test (RIM)		$393,780	$179,035	($214,746)	0.455
Participant Cost Test (PCT)		$13,141	$251,619	$238,479	19.148
Lifecycle Revenue Impacts ($/kWh)				$0.0000720417	
Discounted Participant Payback (years)				0.27	

Measure Group Inputs and Assumptions:

Refrigerators	Value	Source and Notes
Number of Units	629	Annual results 2010
Gross kWh/Unit	1,149	*Evaluation of Utah Refrigerator Recycling Program* - Kema - July 31, 2007
Gross kWh/Year Savings (at Site)	722,721	Annual results 2010 (Gross at Site)
Net To Gross Ratio	0.57	*Evaluation of Utah Refrigerator Recycling Program* - Cadmus - 2010
Measure Life (Years)	5	*Evaluation of Utah Refrigerator Recycling Program* - Cadmus - 2010
2008 IRP Decrement Load Shape		East Side Residential Whole House

Freezers	Value	Source and Notes
Number of Units	159	Annual results 2010
Gross kWh/Unit	1,590	*Evaluation of Utah Refrigerator Recycling Program* - Kema - July 31, 2007
Gross kWh/Year Savings (at Site)	252,825	Annual results 2010 (Gross at Site)
Net To Gross Ratio	0.50	*Evaluation of Utah Refrigerator Recycling Program* - Cadmus - 2010
Measure Life (Years)	5	*Evaluation of Utah Refrigerator Recycling Program* - Cadmus - 2010
2008 IRP Decrement Load Shape		East Side Residential Whole House

Savings Kits	Value	Source and Notes
Number of Units	741	Annual results 2010
Gross kWh/Unit	81	Evaluation of Utah Refrigerator Recycling Program - Kema - July 31, 2007
Gross kWh/Year Savings (at Site)	60,021	Annual results 2010 (Gross at Site)
Net To Gross Ratio	0.63	*Evaluation of Utah Refrigerator Recycling Program* - Cadmus - 2010
Measure Life (Years)	6.6	*Evaluation of Utah Refrigerator Recycling Program* - Cadmus - 2010.
2008 IRP Decrement Load Shape		East Side Residential Whole House

Process and Impact Evaluation

Process and impact evaluations were completed during 2010. The Company during 2010 received process and impact evaluations for program years 2006 to 2008. Results of those evaluations are available at www.pacificorp.com/es/dsm/idaho

In the future, the Company intends to complete process and impact evaluations on a two year cycle for each program in the energy efficiency and peak reduction portfolio. The timing and cycle of evaluations may vary based on maturity of the program, changes in the marketplace, changes in underlying codes and standards and the potential cost of evaluation.

Low Income Weatherization – Schedule 21

The following tables outline the primary inputs and assumptions utilized in the cost effectiveness calculations for the program.

Program Inputs - Low Income Weathization			
Gross kWh/Year Savings (at Site)		71,346	Annual results 2010 (Gross at Site)
Program Management and Administration Costs	$	124,076	Annual costs 2010
Utility Admin	$	9,596	Annual costs 2010
Total Utility Costs	$	133,672	Annual costs 2010
Total Participant Costs		NA	There are no participant costs for this program.
Net To Gross Ratio		1.00	Low income support. NTG assumed to be 1.0
Measure Life (Years)		30	Various Lives By Measure - 2005 Quantec Idaho Low Income Weatherization Program Analysis in Support of Tariff Revision (8/22/05)
2008 IRP Decrement Load Shape			East Side Residential Whole House

All Measures				AC: IRP 46% LF Decrement	
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost Ratio
Total ResourceCost Test (PTRC) + Conservation Adder	0.1330	$133,672	$97,585	($36,087)	0.730
Total Resource Cost Test (TRC) No Adder	0.1330	$133,672	$88,714	($44,958)	0.664
Utility Cost Test (UCT)	0.1330	$133,672	$88,714	($44,958)	0.664
Rate Impact Test RIM)		$230,317	$88,714	($141,603)	0.385
Participant Cost Test (PCT)		$0	$96,645	$96,645	NA
Lifecycle Revenue Impacts ($/kWh)				$0.0000151278	
Discounted Participant Payback (years)				NA	

Process and Impact Evaluation

A process and impact evaluations was initiated during 2010 for program years 2007 - 2009. Results of those evaluations are expected to be complete in the second quarter of 2011.

In the future, the Company intends to complete process and impact evaluations on a two year cycle for each program in the energy efficiency and peak reduction portfolio. The timing and cycle of evaluations may vary based on maturity of the program, changes in the marketplace, changes in underlying codes and standards and the potential cost of evaluation.

Energy FinAnswer – Schedule 125

The following tables outline the primary inputs and assumptions utilized in the cost effectiveness calculations for the program.

Program Inputs - Energy FinAnswer		
Gross kWh/Year Savings (at Site)	1,475,439	Annual results 2010 (Gross at Site)
Program Management and Administration Costs	$ 261,588	Annual costs 2010
Incentives	$ 107,598	Annual costs 2010
Total Utility Costs	$ 369,186	Annual costs 2010
Total Participant Costs	$ 224,338	Incremental costs incurred by consumers based on receipts provided.
Net To Gross Ratio	0.75	Evaluation of Energy FinAnswer Program - Cadmus - 2010
Measure Life (Years)	15	Evaluation of FinAnswer Express - Cadmus - 2010
2008 IRP Decrement Load Shape		East Side System

All Measures				AC: IRP 65% LF Decrement	
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost Ratio
Total Resource Cost Test (PTRC) + Conservation Adder	0.0410	$429,842	$1,033,924	$604,082	2.405
Total Resource Cost Test (TRC) No Adder	0.0410	$429,842	$939,931	$510,089	2.187
Utility Cost Test (UCT)	0.0352	$369,186	$939,931	$570,745	2.546
Rate Impact Test (RIM)		$955,008	$939,931	($15,077)	0.984
Participant Cost Test (PCT)		$168,254	$693,420	$525,167	4.121
Lifecycle Revenue Impacts ($/kWh)				$0.0000008314	
Discounted Participant Payback (years)				3.36	

Savings Calculations and Reporting:

Savings reported for the Energy FinAnswer program are based on project and measure specific verified savings. Preliminary engineering savings and costs estimates are completed during project scoping by a pre-qualified third party energy engineering firm working under contract with the company. Savings and costs are further refined into an energy analysis completed by the same firm. Once the customer installs and commissions (if required) the project, a post-installation inspection is conducted and the savings are re-calculated for each project. Incentives are then paid on final inspected savings amounts. Measure costs are gathered from customer invoices.

Process and Impact Evaluation

Process and impact evaluations were completed during 2010. The Company during 2010 received a process and impact evaluation for program year 2008. Results of the evaluation are available at www.pacificorp.com/es/dsm/idaho

In the future, the Company intends to complete process and impact evaluations on a two year cycle for each program in the energy efficiency and peak reduction portfolio. The timing and cycle of evaluations may vary based on maturity of the program, changes in the marketplace, changes in underlying codes and standards and the potential cost of evaluation.

FinAnswer Express – Schedule 115

The following tables outline the primary inputs and assumptions utilized in the cost effectiveness calculations for the program.

Program Inputs - FinAnswer Express		
Gross kWh/Year Savings (at Site)	3,534,752	Annual results 2010 (Gross at Site)
Program Management and Administration Costs	$ 327,391	Annual costs 2010
Incentives	$ 293,098	Annual costs 2010
Total Utility Costs	$ 620,489	Annual costs 2010
Total Participant Costs	$ 906,048	Actual customer costs incurred based on project close-out documentation (invoices) - less any adjustments (if necessary) for baseline equipment.
Net To Gross Ratio	0.76	*Evaluation of FinAnswer Express Program* - Cadmus - 2010
Measure Life	12	*Evaluation of FinAnswer Express Program* - Cadmus - 2010

All Measures				AC: IRP 65% LF Decrement	
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost Ratio
Total Resource Cost Test (PTRC) + Conservation Adder	0.0431	$1,015,988	$2,222,661	$1,206,673	2.188
Total Resource Cost Test (TRC) No Adder	0.0431	$1,015,988	$2,020,601	$1,004,613	1.989
Utility Cost Test (UCT)	0.0264	$620,490	$2,020,601	$1,400,111	3.256
Rate Impact Test (RIM)		$2,344,001	$2,020,601	($323,400)	0.862
Participant Cost Test (PCT)		$688,596	$2,016,609	$1,328,012	2.929
Lifecycle Revenue Impacts ($/kWh)				$0.0000855886	
Discounted Participant Payback (years)				4.04	

Measure Group Inputs and Assumptions:

Lighting	Value	Source and Notes
Gross kWh/Year Savings (at Site)	1,147,600	Annual results 2010 (Gross at Site)
Program Management and Administration Costs	$ 106,291	Allocated percentage (based on kWh contribution) of non -incentive costs for 2010.
Incentives	$ 124,585	Annual costs 2010
Total Utility Costs	$ 230,876	Annual costs 2010
Total Participant Costs	$ 463,358	Retrofit lighting costs are based on actual customer costs. New construction lighting costs are deemed based on a combination of vendor surveys and third party data.
Net To Gross Ratio	0.76	*Evaluation of FinAnswer Express Program* - Cadmus - 2010
Measure Life (Years)	12	*Evaluation of FinAnswer Express Program* - Cadmus - 2010
2008 IRP Decrement Load Shape		East Side Commercial Lighting

Non-Lighting	Value	Source and Notes
Gross kWh/Year Savings (at Site)	2,387,152	Annual results 2010 (Gross at Site)
Program Management and Administration Costs	$ 221,100	Allocated percentage (based on kWh contribution) of non -incentive costs for 2010.
Incentives	$ 168,514	Annual costs 2010
Total Utility Costs	$ 389,613	Annual costs 2010
Total Participant Costs	$ 442,690	Measures receiving custom incentives are actual costs. Motors and HVAC are deemed costs from a combination of vendors and third party data. - verify with Nexant.
Net To Gross Ratio	0.76	*Evaluation of FinAnswer Express Program* - Cadmus - 2010
Measure Life (Years)	12	*Evaluation of FinAnswer Express Program* - Cadmus - 2010
2008 IRP Decrement Load Shape		East Side System

Cost Effectiveness Inputs at the Measure Level:

The savings estimates from a third party administrator are the basis for several savings calculations tools used to manage the Idaho FinAnswer Express program. Savings from lighting is calculated through an Excel based tool built and maintained by the program staff that includes deemed wattages by fixture types for both baseline and replacement fixtures. Baseline (pre) and post fixture counts along with hours of operation are input on a project specific basis. For each project, the lighting tool calculates energy and average demand savings, incentives, the value of energy and demand savings, simple paybacks with and without incentives, counts of replaced fixture by type and several other project specific metrics.

Savings from NEMA premium motors are calculated using a spreadsheet based tool referencing deemed energy and capacity values based on horsepower size and sector (i.e., commercial and industrial). These values are derived from efficiency gains and operating hour assumptions.

Savings from mechanical and other energy efficiency measures are calculated in a manner similar to motors.

Cost effectiveness inputs included in this section are the aggregations of savings and expenditures in two large categories – lighting and non-lighting.

Process and Impact Evaluation

Process and impact evaluations were completed during 2010. The Company during 2010 received process and impact evaluations for program years 2006 to 2008. Results of those evaluations are available at www.pacificorp.com/es/dsm/idaho

In the future, the Company intends to complete process and impact evaluations on a two year cycle for each program in the energy efficiency and peak reduction portfolio. The timing and cycle of evaluations may vary based on maturity of the program, changes in the marketplace, changes in underlying codes and standards and the potential cost of evaluation.

Agricultural Energy Services (Irrigation Energy Savers) – Schedule 155

The following tables outline the primary inputs and assumptions utilized in the cost effectiveness calculations for the program.

Agricultural Energy Services (Irrigation Energy Savers)		
Gross kWh/Year Savings (at Site)	2,515,169	Annual results 2010 (Gross at Site)
Program Management and Administration Costs	$ 386,085	Annual costs 2010
Incentives	$ 250,924	Annual costs 2010
Total Utility Costs	$ 637,009	Annual costs 2010
Total Participant Costs	$ 561,830	Combination of deemed and actual costs depending on the measure type.
Net To Gross Ratio	0.74	Evaluation of Irrigation Energy Savers Program, Cadmus 2010
Measure Life		At program level, it is a weighted average of the measure group inputs.

All Measures				AC: IRP 16% Commercial Cooling	
	Levelized $/kWh	Costs	Benefits	Net Benefits	Benefit/Cost Ratio
Total Resource Cost Test (PTRC) + Conservation Adder	0.0825	$796,222	$933,430	$137,208	1.172
Total Resource Cost Test (TRC) No Adder	0.0825	$796,222	$848,573	$52,351	1.066
Utility Cost Test (UCT)	0.0660	$637,010	$848,573	$211,563	1.332
Rate Impact Test (RIM)		$1,129,637	$848,573	($281,064)	0.751
Participant Cost Test (PCT)		$410,136	$743,551	$333,415	1.813
Lifecycle Revenue Impacts ($/kWh)				$0.0001243095	
Discounted Participant Payback (years)				4.62	

Equipment Exchange and Pivot/linear Upgrades	Value	Source and Notes
Gross kWh/Year Savings (at Site)	1,658,488	Annual results 2010 (Gross at Site)
Program Management and Administration Costs	$ 254,583	Allocated percentage (based on kWh contribution) of non -incentive costs for 2010.
Incentives	$ 146,770	Annual costs 2010
Total Utility Costs	$ 401,353	Annual costs 2010
Total Participant Costs	$ 273,699	Combination of deemed measure costs based on program administrator and actual customer costs submitted with applications
Net To Gross Ratio	0.74	Evaluation of Irrigation Energy Savers Program, Cadmus 2010
Measure Life (Years)	5	Evaluation of Irrigation Energy Savers Program, Cadmus 2010
2008 IRP Decrement Load Shape		East Side Commercial Cooling

System Upgrades	Value	Source and Notes
Gross kWh/Year Savings (at Site)	856,681	Annual results 2010 (Gross at Site)
Program Management and Administration Costs	$ 131,503	Allocated percentage (based on kWh contribution) of non -incentive costs for 2010.
Incentives	$ 104,154	Annual costs 2010
Total Utility Costs	$ 235,657	Annual costs 2010
Total Participant Costs	$ 288,131	Actual customer costs incurred based on project close-out documentation (invoices) - less any adjustments (if necessary) for baseline equipment.
Net To Gross Ratio	0.74	Evaluation of Irrigation Energy Savers Program, Cadmus 2010
Measure Life (Years)	7	Evaluation of Irrigation Energy Savers Program, Cadmus 2010
2008 IRP Decrement Load Shape		East Side Commercial Cooling

Cost Effectiveness Inputs at the Measure Level:

Measure level savings estimates for prescriptive measures for the Irrigation Energy Savers program are based on the *Review and Development of Utah Power's Irrigation Program in Idaho,* prepared by Fazio Engineering on August 31, 2005.

For projects that are not eligible for prescriptive incentive, savings are estimated at the site utilizing program funded engineering.

The Company aggregates savings and incentives for reporting at the program level.

Cost effectiveness inputs included in this section are the aggregations of savings and expenditures in two large categories – Equipment Exchange and Pivot/Linear Upgrades (including nozzles, gaskets, drains, and pivot/linear equipment upgrades) and System Upgrades (including system analysis). These groupings are utilized to reflect similar measure lives.

Process and Impact Evaluation

Process and impact evaluations were completed during 2010. The Company during 2010 received process and impact evaluations for program years 2006 to 2008. Results of those evaluations are available at www.pacificorp.com/es/dsm/idaho

In the future, the Company intends to complete process and impact evaluations on a two year cycle for each program in the energy efficiency and peak reduction portfolio. The timing and cycle of evaluations may vary based on maturity of the program, changes in the marketplace, changes in underlying codes and standards and the potential cost of evaluation.

APPENDIX 2

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

Appendix 2

Schedule 72 & 72A
Idaho Irrigation Load Control *Programs*

2010 Idaho Irrigation Load Control Quantitative Review

7 January 2011

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Report Organization

Idaho Public Utilities Commission Order No. 29209 and Order No. 29416 in Case No. PAC-E-03-14 requires Rocky Mountain Power (the Company), a division of PacifiCorp, prepare an annual report on the *Idaho Irrigation Load Control Program (Program)*. In 2007, and as approved by the Commission in Order No. 30243, Rocky Mountain Power (RMP) initiated a Dispatch irrigation pilot program (Schedule 72A) evaluating the efficacy of a 2-way control technology. This report presents quantitative results on Schedule 72 and Schedule 72A as required by the Commission order. The Schedule 72A assessment will follow the standard report. Summary statistics from both Schedule 72 and Schedule 72A will be combined and presented. Recommendations and Conclusions will be presented. All costs are accrued for the 2010 program year (1 October 2009 through 31 September 2010) with the exception of participation credits.

Unless otherwise noted, data are calculated as of 19 October 2010. It should be further noted that in previous years report analysis was done on nominal (book) values of participating loads. *In 2010 and primarily for Dispatch results we reflect avoided load data based on SCADA analysis of avoided loads.*

Background

Reporting requirements include responses to the following:

1. The number of irrigation customers who were eligible to participate in the *Program*
2. The number of irrigation customers who entered into a load control *Service Agreement*
3. The number of irrigation customers who participated in the *Program* for the full three and one-half months
4. The number of irrigation customers who are not eligible to participate in the following year's *Program*
5. The total dollar amount of credits provided under the *Program* identified by month
6. Proposed changes and/or recommendations to improve the *Program*

2010 Schedule 72 (Scheduled Forward) Results

Table One

Longitudinal and Current Year Scheduled 72 Eligible & Full-Year Participating Sites & Customers

	Participant Sites	Participant Customers
2003 Actual Participants	401	207
2004 Actual Participants	734	340
2005 Actual Participants	1,065	489
2006 Actual Participants	931	478
2007 Actual Participants	681	405
2008 Actual Participants	87	79
2009 Actual Participants	123	112
2010 Actual Participants	122	105
Eligible 2010 Counts	4,701	1,975
Customers NOT eligible to participate 2010	N/A	0

Table Two

2010 Schedule 72 Participation Credits by Month

	June	July	August
Standard Credits	$11,686.82	$15,491.89	$14,630.13
kW Under Contract	3,950.5[1]	4,466.0	4,332.0
Total Credits	$41,808.84		

Note: avoided kW is as of the day of credit issuance

Table Three

Longitudinal and Current Year Scheduled 72 Participation Credits Issued

Year	Total Participation Credits Issued
2003	$277,583.72
2004	$410,325.49
2005	$842,666.80
2006	$925,577.33
2007	$684,924.98
2008	$30,680.65
2009	$43,912.27
2010	$41,808.84

Table Four

Comparative Scheduled 72 & 72A (Total) Costs 2003, 2004 & 2005

Cost Category	2003 Costs (April '03–Sept '03)	2004 Costs Oct '03–Sept '04	2005 Costs Oct '04–Sept '05
Administrative support	$9,613.43	$1,665.29	$851.56
Program evaluation	$2,135.43	$8,369.88	$1,820.00
Field / Equip / Db admin. expenses	$250,222.98	$239,807.03	$326,061.01
Participation credits	$277,583.72	$410,325.49	$842,666.80
Program management	$10,992.99	$55,036.29	$54,826.69
Reporting	$351.79	$1,940.00	$0.00
Total Program costs	$550,900.34	$717,143.98	$1,226,226.06

Note: 2003 costs over 6 month period; subsequent *Program*-year costs are calculated over a 12 month period (1 October thru 31 September)

[1] Throughout this report and in all cases avoid demand nominal values are reported at the site and are NOT grossed-up by 10.39% for generation thereby taking into account T&D losses.

Table Four (cont)

Comparative Load Control Program (Total) Costs 2006, 2007 & 2008

Cost Category	2006 Costs Oct '05–Sept '06	2007 Costs Oct '05–Sept '06	2008 Costs Oct '07–Sept '08
Administrative support	$194.60	$1,500.00	$1,640.50
Program evaluation	$1,125.00	$2,268.75	$2,268.75
Field / Equip / Db admin. expenses	$330,802.05	$747,664.85	$2,816,386.26
Participation credits	$925,577.33	$1,752,930.47	$5,993,868.57
Program management	$42,554.85	$80,144.00	$94,051.68
Reporting	$0.00	$0.00	$0.00
Total Program costs	$1,300,253.83	$2,584,508.07	$8,908,215.76

Table Four (cont)

Comparative Load Control *Program* (Total) Costs 2009 & 2010

Cost Category	2009 Costs Oct '08–Sept '09	2010 Costs Oct '09–Sept '010
Administrative support	$253.27	$0.0
Program evaluation	$4,195.00	$11,758
Field / Equip / Db admin. expenses	$3,361,818.68	$3,801,022.87
Participation credits	$7,246,582.84	$8,101,480.75
Program management	$67,760.75	$117,518.03
Reporting	$0.0	$0.0
Total Program costs	$10,680,610.54	$12,031,779.65

Table Five

Schedule 72 Program Nominal Loads by Participation Option

Participation Option	Site Cnt.	June Avoided kW	July Avoided kW	Aug. Avoided kW
Option I m w 2-8	52	1,713.5	1,797.5	2,019.0
Option I t th 2-8	39	910.0	1,012.5	992.0
Option II m w 3-6	10	293.5	393.5	298.5
Option II m w 4-7	0	0	0	0
Option II t th 3-6	0	0	0	0
Option II t th 4-7	1	20.0	20.5	19.0
Option III m t w th 3-6	8	344.5	376.0	316.5
Option III m t w th 4-7	1	31.0	31.0	30.0
Option IV m 2-8	8	264.5	384.0	290.5
Option IV w 2-8	3	182.5	273.5	275.0
Schedule Forward Totals	*122*	*3,760*	*4,289*	*4,241*

Tables Six through Nine transpose the data presented in Table Five into hourly dispatch schedules by each of the four Schedule Forward dispatch days (Monday–Thursday). Each of the four subsequent tables indicates the avoided kW by month, control day (Monday–Thursday) and hour.

Table Six

Schedule 72 2010 Nominal kW by Month, **Monday** Control Day & Hour

JUNE Monday Avoided kW by Hour						
Hour	2:00-2:59	3:00-3:59	4:00-4:59	5:00-5:59	6:00-6:59	7:00-7:59
Avoided kW	1,978.0	2,616.0	2,647.0	2,647.0	2,009.0	1,978.0

JULY Monday Avoided kW by Hour						
Hour	2:00-2:59	3:00-3:59	4:00-4:59	5:00-5:59	6:00-6:59	7:00-7:59
Avoided kW	2,181.5	2,951.0	2,982.0	2,982.0	2,212.5	2,181.5

AUGUST Monday Avoided kW by Hour						
Hour	2:00-2:59	3:00-3:59	4:00-4:59	5:00-5:59	6:00-6:59	7:00-7:59
Avoided kW	2,309.5	2,924.5	2,954.5	2,954.5	2,339.5	2,309.5

Table Seven

Schedule 72 2010 Nominal kW by Month, **Tuesday** Control Day & Hour

JUNE Tuesday Avoided kW by Hour						
Hour	2:00-2:59	3:00-3:59	4:00-4:59	5:00-5:59	6:00-6:59	7:00-7:59
Avoided kW	910.0	1254.5	1305.5	1305.5	961.0	910.0

JULY Tuesday Avoided kW by Hour						
Hour	2:00-2:59	3:00-3:59	4:00-4:59	5:00-5:59	6:00-6:59	7:00-7:59
Avoided kW	1,012.5	1,388.5	1,440.0	1,440.0	1,064.0	1,012.5

AUGUST Tuesday Avoided kW by Hour						
Hour	2:00-2:59	3:00-3:59	4:00-4:59	5:00-5:59	6:00-6:59	7:00-7:59
Avoided kW	992.0	1,308.5	1,357.5	1,357.5	1,041.0	992.0

Table Eight

Schedule 72 2010 Nominal kW by Month, **Wednesday** Control Day & Hour

JUNE Wednesday Avoided kW by Hour						
Hour	2:00-2:59	3:00-3:59	4:00-4:59	5:00-5:59	6:00-6:59	7:00-7:59
Avoided kW	1,896.0	2,534.0	2,565.0	2,565.0	1,927.0	1,896.0

JULY Wednesday Avoided kW by Hour						
Hour	2:00-2:59	3:00-3:59	4:00-4:59	5:00-5:59	6:00-6:59	7:00-7:59
Avoided kW	2,071.0	2,840.5	2,871.5	2,871.5	2,102.0	2,071.0

AUGUST Wednesday Avoided kW by Hour						
Hour	2:00-2:59	3:00-3:59	4:00-4:59	5:00-5:59	6:00-6:59	7:00-7:59
Avoided kW	2,294.0	2,909.0	2,939.0	2,939.0	2,324.0	2,294.0

Table Nine

Schedule 72 2010 Nominal kW by Month, **Thursday** Control Day & Hour

JUNE Thursday Avoided kW by Hour						
Hour	2:00-2:59	3:00-3:59	4:00-4:59	5:00-5:59	6:00-6:59	7:00-7:59
Avoided kW	910.0	1,254.5	1,305.5	1,305.5	961.0	910.0

JULY Thursday Avoided kW by Hour						
Hour	2:00-2:59	3:00-3:59	4:00-4:59	5:00-5:59	6:00-6:59	7:00-7:59
Avoided kW	1,012.5	1,388.5	1,440.0	1,440.0	1,064.0	1,012.5

AUGUST Thursday Avoided kW by Hour						
Hour	2:00-2:59	3:00-3:59	4:00-4:59	5:00-5:59	6:00-6:59	7:00-7:59
Avoided kW	992.0	1,308.5	1,357.5	1,357.5	1,041.0	992.0

Cost-effectiveness analyses

Cost-effectiveness is calculated for the following program components:

1. Schedule 72 (Scheduled Forward) only
2. Schedule 72A (Dispatch) only
3. Schedule 72 and Schedule 72A (combined)

Results on each of the four standard utility industry tests–(1) Total Resource Cost (TRC); (2) Utility; (3) Ratepayer and (4) Participant will be provided for each of the three aforementioned program cases. The tests for Schedule 72 (Scheduled Forward option) will be based upon the cost and nominal MW values as defined in Table Ten below[2]. The information below will describe the methodology used in evaluating each of the subsequent program components.

The Program cost-effectiveness analysis is based on the ratio of the present value of the Program's benefits to costs and the net benefits (benefits minus costs), discounted at the appropriate rate for the various benefit/cost tests[3]. The benefits (avoided costs) are based on the calculations as defined by the Company's Integrated Resource Planning (IRP) organization and presented to the Idaho Public Utilities Commission, and the Idaho Irrigation Pumpers' Association in a report titled *Proposed Valuation Methodology for the Idaho Irrigation Load Control Program.* It should be noted that the avoided costs used in all cost-effectiveness analyses calculations presented in this report considered the overall program size (Scheduled Forward + Dispatch program options) rather than individual program characteristics. From an analytic perspective it is clear that the Dispatch initiative is valued higher than a Scheduled Forward option. That said the extraordinarily smaller size of the Schedule Forward initiative compared to the Dispatch option simply did not warrant a separate avoided cost analysis.

Table Ten

2010 Benefit / Cost Categories & Values–Schedule 72

Cost Categories	Cost Values	Benefit Category	Benefit Value
Administrative support	$0.0	$/kW-yr avoided	$73.09/kW
Program evaluation	$175.46		
Field / Equip / Db admin. expenses	$56,722.69		
Participation credits	$41,808.84		
Program management	$1,753.72		
Total	$100,460.72		

Note: with the exception of participation credits costs have been allocated based on the percent of load the Schedule Forward option comprises of the total (combined) irrigation load control programs.

Costs used in these calculations include administrative costs, contractor costs (field technician, customer service, equipment and back office system design / administration) and associated participant credits costs.

[2] To the extent possible, certain cost categories have been allocated by (1) the respective Schedule initiative and (2) percent of participating load.
[3] Note that no discounting of costs or benefits was required in this analysis since all costs and benefits occurred in program year 2010.

The participation credits are not included in the Total Resource Cost (TRC) test because they are a transfer payment from the utility to the participants.

The cost-effectiveness of the Program was calculated by Cadmus using a simplified spreadsheet analysis. This analysis multiplies nominal demand reductions for the June, July and August period (as is consistent with previous program year calculations) as a result of customers participating in the Program by the estimated value of avoided demand noted above. As noted, the avoided demand value of is $73.09/kW-yr is increased by 10.39% to account for the effect of T&D line losses, resulting in a value of $81.56/kW-yr used in the cost-effectiveness calculations.

Based on previous research that showed energy use is 'shifted' rather than 'avoided', lost revenues are not included as a cost and energy savings are not applicable as indicated above.

As shown in Table Eleven, the Scheduled Forward component of the program passes the TRC Test. The Scheduled Forward program also passes the Utility and Ratepayer Test. Since the participant incurs no costs the benefit/cost ratio would be infinite for the Participant Test. Accordingly, for the Participant Test the value is indicated as 'N/A' in Table Eleven.

Table Eleven
2010 Cost-effectiveness Analyses–Schedule 72

Test	Benefits	Costs	Net Benefits	Benefit/Cost Ratio
TRC	$147,542.97	$58,651.87	$88,891.10	2.52
Utility	$147,542.97	$100,460.71	$47,082.26	1.47
Ratepayer	$147,542.97	$100,460.71	$47,082.26	1.47
Participant	$41,808.84	$0.00	$41,808.84	N/A

Measurement & Verification (M&V) processes

The control equipment provides log files that can authoritatively determine issues of grower fraud and/or tampering with the control equipment. Throughout the 2010 season there remained a residual amount of confusion among growers relative to equipment / program operations. Accordingly, the Irrigation Management Team decided that it would be important to provide additional M&V field technician site visits. This was done to meet customer services as well as M&V objectives. In the end there were no sites reported to be out of compliance relative to grower fraud. There was, throughout each of the site visits, significant attention to training and easing grower fears / concerns regarding the remote control equipment and how best to operate the equipment relative to agri-operation requirements.

2010 Schedule 72A (Dispatch) Results

Table Twelve

Schedule 10 Eligible & Full-Year Participating Sites & Customers

	Participant Sites	Participant Customers
2008 Actual Participants	1,491	530
2009 Actual Participants	1,927	826
2010 Actual Participants	2,194	773
Eligible 2010 Counts	4,701	1,975
Customers NOT eligible to participate 2010	N/A	0

Note: 'customers' is a calculated number and is based on a query employing the 'distinct' operand

Customer Opt-Outs

Schedule 72A permits growers to 'opt-out' of five Dispatch Events throughout the Irrigation Season. Each of these opt-out events incurred a cost resulting in a reduction to the customer's Load Control Service Credit. The cost to opt-out is the day-ahead ($/MWh) RMP would otherwise have to pay for power during that dispatch period. A summary of opt-outs, liquidated damages and kW not avoided by each of the Dispatch Events is presented in Table Thirteen. Table Fourteen summarizes 2010 dispatch dates and durations.

Table Thirteen

Opt-outs, Liquidated Damages, kW[4] NOT Avoided and $/MWh by Dispatch Event

Count	Dispatch Date	Weekday	Count of Sites Opting-outs	Liquidated Damages	kW NOT Avoided	$/MWh (day ahead)
1	29-Jun	Thursday	40	$856.05	4,553.5	$47.00
2	8-Jul	Thursday	45	$1,040.61	5,946.0	$43.75
3	15-Jul	Thursday	125	$4,124.64	19,830.0	$52.00
4	16-Jul	Friday	98	$3,587.08	15,802.0	$56.75
5	19-Jul	Monday	90	$3,920.19	17,269.5	$56.75
6	20-Jul	Tuesday	142	$4,909.27	23,157.0	$53.00
7	26-Jul	Monday	81	$2,177.28	11,458.5	$47.50
8	2-Aug	Monday	33	$986.39	4,811.5	$51.25
9	5-Aug	Thursday	40	$1,502.75	7,551.5	$49.75
10	24-Aug	Thursday	25	$1,258.80	5,245.0	$60.00
11	26-Aug	Thursday	21	$697.98	3,116.0	$56.00
	totals / average ($/MWh)		740	$25,061.04	118,740.5	$52.16

[4] kW represents connected load based on the average monthly demand for June, July and August for 2008 and 2009.

Table Fourteen
2010 Dispatch Dates & Durations

Dispatch dates	Dispatch Duration (hours)	Dispatch dates	Dispatch Duration (hours)
June		**August**	
Tuesday, June 29, 2010	4	Monday, August 02, 2010	4
		Thursday, August 05, 2010	4
July		Tuesday, August 24, 2010	4
Thursday, July 08, 2010	4	Thursday, August 26, 2010	4
Thursday, July 15, 2010	4		
Friday, July 16, 2010	4	**Grid-ops dispatch**	
Monday, July 19, 2010	4	Tuesday, June 01, 2010	1
Tuesday, July 20, 2010	4	Wednesday, June 02, 2010	1
Monday, July 26, 2010	4	Monday, June 07, 2010	1
		Wednesday, July 14, 2010	4
Grand Total hours	**51**		

Dispatch Events

Problem definition

In 2009 the Customer & Community Management (C&CM) organization along with the Irrigation Management Team learned that Dispatch Events (DE) could no longer simply be implemented in a single 4-hour window. The reason for this was as follows:

- The distribution system in southeast Idaho that serves rural, primarily agri-irrigtion areas has very little / no automation. Accordingly, capacitors are manually engaged each season as irrigation load increases at the beginning of the season. The capacitors are disengaged at the end of the season in a similar manner.
- Pump load (motors) create inductive line reactance (lagging); line capacitors (capacitance reactance) are placed on the circuits to counter-act this effect so the sinusoid electrical wave is at unity or as close to unity as possible thereby maintaining operational efficiency.
- By the time irrigation load control begins to execute dispatch events all line capacitor banks have been manually engaged.
- To compensate, the Company would have to physically disengage the capacitor banks in anticipation of a DE and correspondently reengage the capacitor banks following each event in order to accommodate the return of the inductive load, an activity that from a resource perspective is not supportable.
- Moreover, and with the precipitous and instantaneous drop in load, the voltage regulators (which are in the distribution substation as well as on the distribution circuits themselves) simply do not have sufficient time to make a 'step change' to maintain appropriate voltages. Note: regulators require ~90s to 'adjust' to a change in the load.

- Due to (1) the magnitude of the program's participating loads, (2) the concentration of loads on agricultural-dominant substations and (3) circuits not having the capability to scale loads DE events were inadvertently creating a situation where there is (1) too much capacitor reactance and (2) too high of voltage (outside of IEEE + tariff specifications).

To avoid this situation DE's require intelligent scheduling / implementation. In 2010 and beyond DE's would be required to be implemented in such a way that Irrigation Load Control provided a rudimentary 'Smart Grid'. Additionally and anticipated, 'smart implementation' would augment existing infrastructure assets and perhaps improve Grid performance. A description of the problem solving process and the benefits associated with the resultant approach are discussed below.

Analysis and solution

To deliver on this objective a 6-month modeling exercise was undertaken. The effort involved professional resources from Customer & Community Management (C&CM), Grid-Ops, Area Planning, Distribution Engineering, Metering, and Demand Side Management. The effort began with an inventory of loads for each of the five transmission substations that provide service to those geo-spatial areas where there is extraordinary concentration of program participants. In fact, 77.9% of total program participation (on a load basis) is served by one of the five transmission substations.

Working with Distribution Engineering (Rexburg Service Center) distribution substations and their associated circuits were mapped to participating pump / pivot loads. Mapping was completed using the Company's CADOPS Engineering Database. Coincident with the aforementioned mapping effort the Area Planning organization for Idaho prepared a 'flicker study' that would model upper and lower limits of loads that could be removed / added to the circuit in any single 'step' before a power excursion >3% would be generated. The 3% variation was determined to be the acceptable limit for tariff and IEEE compliance.

Pursuant to the flick study and armed with distribution substation performance parameters, the Irrigation Management Team constructed a step-function load model for each circuit, distribution substation and transmission substation. Each DE step-function had a 'bounded kW' value for load removal. Specific sites and the associated grower were identified and 'tagged' by circuit, distribution substation and transmission substation. Field technicians most familiar with the area served by a transmission substation were asked to allocate farms / loads in the most appropriate manner to (1) meet target load drops as defined above and (2) accommodate farming operations.

Field technicians were then tasked to visit each grower together with the appropriate C&CM representative. The field technician, C&CM representative along with the grower reviewed the specific 'dispatch slot' to determine if the specified 'dispatch slot' would work given their farms, labor, equipment and irrigation delivery system configurations. Subsequent feedback necessitated changes to the schedule. Altogether 52 separate dispatches were designed and grower sites slotted into one of the following three 4-hour DE time periods.

- 11:00a....................3:00p
- 2:00p......................6:00p
- 3:00p......................7:00p

Once into the dispatch season the Irrigation Management Team learned from Area Planning that the Hamer Distribution Substation which was originally planned to be fed out of Jefferson Transmission Substation would, for the 2010 season, continue to be fed out of Big Grassy. After the first four DE's the C&CM representative along with the Irrigation Management Team was informed that DE's were continuing to over-volt the Big Grassy transmission sub. Further dispatching would require that still further load be shifted away from the 11:00a – 7:00p dispatch window. Accordingly, a fourth dispatch window was established that operated from 7:00a – 11:00a. Approximately 20 MW of load was shifted to the 7:00a – 11:00a dispatch window. Here as in other aspects of the Irrigation Load Control initiative, growers stepped-up and volunteered to change their schedule to accommodate the new requirement.

Results

The result of the stair–stepping of load into and out of DE was a remarkable success. The stair-stepping worked as expected. Distribution Engineering and Area Planning reported no voltage excursions beyond standard operating parameters. The impact of stair–stepping on the Big Grassy transmission substation is depicted in Illustration One which comes directly from Company SCADA data on a sample DE day. Nearly identical results were replicated on each of the DEs across each of the transmission substations.

Illustration One

Stair–Stepping Big Grassy Distribution Substation

Grid-ops tap change dispatches

Grid Operations together with Idaho Area Planning decided in early July that a 2-step tap change would be required on the Big Grassy transmission substation in order to maintain voltages within tariff specifications. Grid Ops approached the Irrigation Management Team requesting a 'special' 1-hour dispatch of ~20 MW on the Big Grassy substation. Coinciding with this DE would be a shift in the load that feeds the associated distribution subs (Hamer, Camas, Dubois and Sandune). Executing the tap change in this manner would allow customers to enjoy continuous service without the inconvenience of a planned outage for ALL loads on the four distribution substation associated with the Big Grassy transmission substation. Plans to implement this transition were made for 1 July. The 1 July effort failed due to a problem with the phase shifter on the line to Anaconda. A second attempt was made the following day (2 July) but this attempt also failed as the loads were out of synch and the tap change could not be negotiated. A third attempt was initiated on 7 July. The 7 July effort was successful and is so illustrated in Illustration Seven along with the 1 July and 2 July failed attempts.

Grid Operations again contacted the Company's Irrigation C&CM and the Irrigation Management Team on 14 July. This time Grid-Ops requested what was at first a 3-hour dispatch and later revised for an additional single hour in response to a five-mile area of line that had been destroyed in a brush fire. The results of these special Grid-Ops dispatches are depicted in Illustration Seven.

Illustration Seven

Impacts of Grid Operations Dispatch Events

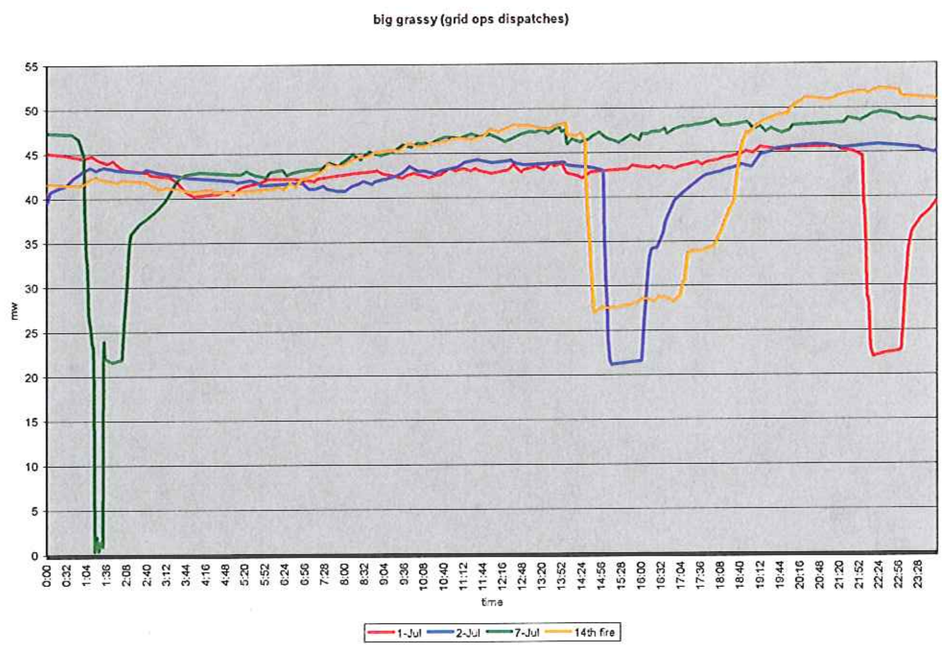


Table Fifteen provides the estimated loads by dispatch hour for each of the DE's in 2010. The use of estimated data is markedly different from previous year reporting where only nominal (book) loads were used. To the extent possible SCADA estimates provide the basis for avoided kW. The reader should keep in mind that the values reported on the five transmission substations reflect 77.9% of total program participation. To assess total program participation one would need to 'gross-up' the avoided kW values by dividing the reported kW by 77.9%. This grossing-up of estimates is performed for the data reported in Table Nineteen.

The loads reflected in Table Fifteen do NOT take into account credits for AMD dispatch sites and their associated loads. The AMD loads, of course, are not available for dispatch as they were dedicated for the AMD trials. Accordingly, the net estimated realized loads for dispatch across each of the five transmission substations are presented in Table Sixteen.

Table Fifteen

Dispatch Program Only: SCADA Estimated Load (kW) Impacts x Dispatch Event x Designated Northern Tier Transmission Substations (Amps, Big Grassy, Bonneville, Jefferson & Rigby)

Date	Weekday	7:00-7:59	8:00-8:59	9:00-9:59	10:00-10:59	11:00-11:59	12:00-12:59	1:00-1:59	2:00-2:59	3:00-3:59	4:00-4:59	5:00-5:59	6:00-6:59
29-Jun	Thursday	0.0	0.0	0.0	0.0	53,225.2	53,225.2	53,225.2	87,725.2	106,918.7	106,918.7	106,918.7	72,418.7
8-Jul	Thursday	0.0	0.0	0.0	0.0	53,225.2	53,225.2	53,225.2	87,725.2	106,918.7	106,918.7	106,918.7	72,418.7
15-Jul	Thursday	0.0	0.0	0.0	0.0	53,225.2	53,225.2	53,225.2	87,725.2	106,918.7	106,918.7	106,918.7	72,418.7
16-Jul	Friday	0.0	0.0	0.0	0.0	53,225.2	53,225.2	53,225.2	87,725.2	106,918.7	106,918.7	106,918.7	72,418.7
19-Jul	Monday	18,000.0	18,000.0	18,000.0	18,000.0	34,225.2	34,225.2	34,225.2	67,782.6	102,976.1	102,976.1	102,976.1	69,418.7
20-Jul	Tuesday	18,000.0	18,000.0	18,000.0	18,000.0	34,225.2	34,225.2	34,225.2	67,782.6	102,976.1	102,976.1	102,976.1	69,418.7
26-Jul	Monday	18,000.0	18,000.0	18,000.0	18,000.0	34,225.2	34,225.2	34,225.2	67,782.6	102,976.1	102,976.1	102,976.1	69,418.7
2-Aug	Monday	18,000.0	18,000.0	18,000.0	18,000.0	34,225.2	34,225.2	34,225.2	67,782.6	102,976.1	102,976.1	102,976.1	69,418.7
5-Aug	Thursday	18,000.0	18,000.0	18,000.0	18,000.0	34,225.2	34,225.2	34,225.2	67,782.6	102,976.1	102,976.1	102,976.1	69,418.7
24-Aug	Thursday	18,000.0	18,000.0	18,000.0	18,000.0	34,225.2	34,225.2	34,225.2	67,782.6	102,976.1	102,976.1	102,976.1	69,418.7
26-Aug	Thursday	18,000.0	18,000.0	18,000.0	18,000.0	34,225.2	34,225.2	34,225.2	67,782.6	102,976.1	102,976.1	102,976.1	69,418.7

Note: to estimate the total program load impacts x hour one should divide each of the values in the table above by 77.9%.

Table Sixteen

Dispatch Program Realized Net Load: SCADA Estimated Derived (kW) Impacts x Dispatch Event x Designated Northern Tier Transmission Substations (Amps, Big Grassy, Bonneville, Jefferson & Rigby

Date	Weekday	7:00-7:59	8:00-8:59	9:00-9:59	10:00-10:59	11:00-11:59	12:00-12:59	1:00-1:59	2:00-2:59	3:00-3:59	4:00-4:59	5:00-5:59	6:00-6:59
29-Jun	Thursday	0.0	0.0	0.0	0.0	53,225.2	53,225.2	53,225.2	76,751.0	95,944.5	95,944.5	95,944.5	61,444.5
8-Jul	Thursday	0.0	0.0	0.0	0.0	53,225.2	53,225.2	53,225.2	76,751.0	95,944.5	95,944.5	95,944.5	61,444.5
15-Jul	Thursday	0.0	0.0	0.0	0.0	53,225.2	53,225.2	53,225.2	76,751.0	95,944.5	95,944.5	95,944.5	61,444.5
16-Jul	Friday	0.0	0.0	0.0	0.0	53,225.2	53,225.2	53,225.2	75,031.4	94,224.9	94,224.9	94,224.9	59,724.9
19-Jul	Monday	18,000.0	18,000.0	18,000.0	18,000.0	34,225.2	34,225.2	34,225.2	57,028.7	92,222.2	92,222.2	92,222.2	58,664.8
20-Jul	Tuesday	18,000.0	18,000.0	18,000.0	18,000.0	34,225.2	34,225.2	34,225.2	58,481.5	93,675.0	93,675.0	93,675.0	60,117.6
26-Jul	Monday	18,000.0	18,000.0	18,000.0	18,000.0	34,225.2	34,225.2	34,225.2	57,028.7	92,222.2	92,222.2	92,222.2	58,664.8
2-Aug	Monday	18,000.0	18,000.0	18,000.0	18,000.0	34,225.2	34,225.2	34,225.2	57,028.7	92,222.2	92,222.2	92,222.2	58,664.8
5-Aug	Thursday	18,000.0	18,000.0	18,000.0	18,000.0	34,225.2	34,225.2	34,225.2	56,808.4	92,002.0	92,002.0	92,002.0	58,444.5
24-Aug	Thursday	18,000.0	18,000.0	18,000.0	18,000.0	34,225.2	34,225.2	34,225.2	67,782.6	102,976.1	102,976.1	102,976.1	69,418.7
26-Aug	Thursday	18,000.0	18,000.0	18,000.0	18,000.0	34,225.2	34,225.2	34,225.2	67,782.6	102,976.1	102,976.1	102,976.1	69,418.7

Note: the green highlighted areas are those where the AMD loads have been removed from the values presented in Table Fifteen. In fact the AMD dispatch loads extended to the 8:00p hour.

Table Seventeen presents the AMD impacts in the 7:00p-7:59 hour. Note: values in Table Seventeen are negative as these are loads not available for dispatch on the respective DE weekday. Table Eighteen presents net load estimated impacts to the Grid less the Opt-Outs. That is, the column to the far right presents load impacts to northern tier areas served by Amps, Big Grassy, Bonneville, Jefferson or Rigby (what the Grid would actually see in that area). Also presented in the column to the furthest right are the avoided 'grossed-up' loads x hour x DE. Values in June and August have been adjusted based on the percent of load they represent of the max July values. Accordingly, June was factored by 92.7% and August factored by 98.6%.

Table Seventeen:

Dispatch Program Impacts less Nominal Opt-Outs

Date	Weekday	7:00p-7:59p	Date	Weekday	7:00p-7:59p
29-Jun	Thursday	(10,974.2)	26-Jul	Monday	(10,753.9)
8-Jul	Thursday	(10,974.2)	2-Aug	Monday	(10,753.9)
15-Jul	Thursday	(10,974.2)	5-Aug	Thursday	(10,974.2)
16-Jul	Friday	(12,693.7)	24-Aug	Thursday	(10,974.2)
19-Jul	Monday	(10,753.9)	26-Aug	Thursday	(10,974.2)
20-Jul	Tuesday	(9,301.1)			

Table Eighteen:

Net Load Estimated Impacts to the Grid in Northern Tier Areas

Date	Weekday	7:00-7:59	8:00-8:59	9:00-9:59	10:00-10:59	11:00-11:59	12:00-12:59	1:00-1:59	2:00-2:59	3:00-3:59	4:00-4:59	5:00-5:59	6:00-6:59	Impacts Less Opt -Outs	Impacts Grossed-up
29-Jun	Thursday	0.0	0.0	0.0	0.0	53,225.2	53,225.2	53,225.2	76,751.0	95,944.5	95,944.5	95,944.5	61,444.5	155,810.7	200,013.7
8-Jul	Thursday	0.0	0.0	0.0	0.0	53,225.2	53,225.2	53,225.2	76,751.0	95,944.5	95,944.5	95,944.5	61,444.5	166,749.5	214,055.8
15-Jul	Thursday	0.0	0.0	0.0	0.0	53,225.2	53,225.2	53,225.2	76,751.0	95,944.5	95,944.5	95,944.5	61,444.5	152,865.5	196,233.0
16-Jul	Friday	0.0	0.0	0.0	0.0	53,225.2	53,225.2	53,225.2	75,031.4	94,224.9	94,224.9	94,224.9	59,724.9	153,454.4	196,989.0
19-Jul	Monday	18,000.0	18,000.0	18,000.0	18,000.0	34,225.2	34,225.2	34,225.2	57,028.7	92,222.2	92,222.2	92,222.2	58,664.8	149,981.4	192,530.7
20-Jul	Tuesday	18,000.0	18,000.0	18,000.0	18,000.0	34,225.2	34,225.2	34,225.2	58,481.5	93,675.0	93,675.0	93,675.0	60,117.6	146,999.6	188,703.0
26-Jul	Monday	18,000.0	18,000.0	18,000.0	18,000.0	34,225.2	34,225.2	34,225.2	57,028.7	92,222.2	92,222.2	92,222.2	58,664.8	155,792.4	199,990.2
2-Aug	Monday	18,000.0	18,000.0	18,000.0	18,000.0	34,225.2	34,225.2	34,225.2	57,028.7	92,222.2	92,222.2	92,222.2	58,664.8	160,110.8	205,533.8
5-Aug	Thursday	18,000.0	18,000.0	18,000.0	18,000.0	34,225.2	34,225.2	34,225.2	56,808.4	92,002.0	92,002.0	92,002.0	58,444.5	156,975.8	201,509.4
24-Aug	Thursday	18,000.0	18,000.0	18,000.0	18,000.0	34,225.2	34,225.2	34,225.2	67,782.6	102,976.1	102,976.1	102,976.1	69,418.7	180,882.9	232,198.8
26-Aug	Thursday	18,000.0	18,000.0	18,000.0	18,000.0	34,225.2	34,225.2	34,225.2	67,782.6	102,976.1	102,976.1	102,976.1	69,418.7	182,981.4	234,892.7

Table Nineteen presents the Net Load Impacts to the Grid for all Program Areas. In this presentation the value of AMD are added back into the avoided kW values as the Company received benefit on the respective weekdays. Because AMD's fell outside of DE's, calculations were performed to add AMD values as if they executed simultaneous with the DE. Opt-outs are once again excluded from these values as these loads were appropriately captured in credit calculations issued to growers. The values in Table Nineteen are those that are representative of system impacts as a function of the dispatch initiative.

Table Nineteen:
Total Dispatchable Program (grossed-up) Estimated Impacts x Hour x Dispatch Event

Date	Weekday	7:00-7:59	8:00-8:59	9:00-9:59	10:00-10:59	11:00-11:59	12:00-12:59	1:00-1:59	2:00-2:59	3:00-3:59	4:00-4:59	5:00-5:59	6:00-6:59	7:00-7:59
29-Jun	Thursday	0.0	0.0	0.0	0.0	68,325.0	68,325.0	68,325.0	102,987.0	127,625.6	127,625.6	127,625.6	83,338.1	4,461.9
8-Jul	Thursday	0.0	0.0	0.0	0.0	68,325.0	68,325.0	68,325.0	102,987.0	127,625.6	127,625.6	127,625.6	83,338.1	4,461.9
15-Jul	Thursday	0.0	0.0	0.0	0.0	68,325.0	68,325.0	68,325.0	102,987.0	127,625.6	127,625.6	127,625.6	83,338.1	4,461.9
16-Jul	Friday	0.0	0.0	0.0	0.0	68,325.0	68,325.0	68,325.0	106,254.9	130,893.6	130,893.6	130,893.6	86,606.0	9,937.4
19-Jul	Monday	18,000.0	18,000.0	18,000.0	18,000.0	43,934.8	43,934.8	43,934.8	80,386.5	125,564.3	125,564.3	125,564.3	82,486.8	7,178.9
20-Jul	Tuesday	18,000.0	18,000.0	18,000.0	18,000.0	43,934.8	43,934.8	43,934.8	105,483.0	150,660.8	150,660.8	150,660.8	107,583.3	30,410.5
26-Jul	Monday	18,000.0	18,000.0	18,000.0	18,000.0	43,934.8	43,934.8	43,934.8	80,386.5	125,564.3	125,564.3	125,564.3	82,486.8	7,178.9
2-Aug	Monday	18,000.0	18,000.0	18,000.0	18,000.0	43,934.8	43,934.8	43,934.8	80,386.5	125,564.3	125,564.3	125,564.3	82,486.8	7,178.9
5-Aug	Thursday	18,000.0	18,000.0	18,000.0	18,000.0	43,934.8	43,934.8	43,934.8	77,386.7	122,564.6	122,564.6	122,564.6	79,487.0	4,461.9
24-Aug	Thursday	18,000.0	18,000.0	18,000.0	18,000.0	43,934.8	43,934.8	43,934.8	87,012.3	132,190.1	132,190.1	132,190.1	89,112.6	0.0
26-Aug	Thursday	18,000.0	18,000.0	18,000.0	18,000.0	43,934.8	43,934.8	43,934.8	87,012.3	132,190.1	132,190.1	132,190.1	89,112.6	0.0
					hourly average	52,804.0	52,804.0	52,804.0	92,115.4	129,824.4	129,824.4	129,824.4	86,306.9	7,248.4

Cost-effectiveness analyses

Cost-effectiveness calculations were prepared for each of the four standard utility industry tests in the manner consistent with that described above for the Schedule 72 portion of this program. Benefits and costs for Schedule 72A (Dispatch option) upon which calculations are prepared are presented in Table Twenty below[5].

Again, the cost-effectiveness of the Program was calculated by Cadmus using a simplified spreadsheet analysis. This analysis multiplies nominal demand reductions for the June, July and August period (as is consistent with previous program year calculations) less opt-out MW's by the estimated value of avoided demand. In the case of Schedule 72A, the value of potential avoided demand is based on the volume of avoided kW times dispatch hours and the benefit calculations provided by PacifiCorp. The avoided cost benefits were presented to the Idaho Public Utilities Commission and the Idaho Irrigation Pumpers' Association in a report titled *Proposed Valuation Methodology for the Idaho Irrigation Load Control Program.* The 2010 value was determined to be $73.09/kW-yr. Values are increased by 10.39% to account for the effect of T&D line losses setting the value used in the calculations at $81.56/kW-yr.

Table Twenty
2010 Benefit / Cost Categories & Values–Schedule 72A

Cost Categories	Cost Values	Benefit Category	Benefit Value
Administrative support	$0.0	$/kW-yr avoided	$73.09/kW
Program evaluation	$11,582.54		
Field / Equip / Db admin. expenses	$3,744,300.18		
Participation credits	$7,980,582.30		
Program management	$115,764.31		
Total	$11,852,229.32		

As shown in Table Twenty-One, Schedule 72A passes the TRC, Utility and Ratepayer Tests. The Program also passes the Participant Test. However, since the participant incurs no costs the benefit/cost ratio would be infinite. Accordingly for the Participant Test the value is indicated as 'N/A' in the Benefit/Cost Ratio column.

Table Twenty-One
2010 Cost-effectiveness Analyses

Test	Benefits	Costs	Net Benefits	Benefit/Cost Ratio
TRC	$21,094,596.62	$3,871,647.03	$17,222,949.59	5.45
Utility	$21,094,596.62	$11,852,229.33	$9,242,367.29	1.78
Ratepayer	$21,094,596.62	$11,852,229.33	$9,242,367.29	1.78
Participant	$7,980,582.30	$0.00	$7,980,582.30	N/A

[5] Again, to the extent possible, costs have been allocated by the respective Schedule initiative

2010 Schedule 72 & Schedule 72A Results

This section of the report provides quantitative summaries of the two combined initiatives–Schedule 72 (Scheduled Forward) and Schedule 72A (Dispatch).

Avoided demand

Program nominal impacts by participation option for both Schedule 72 and 72A are presented in Table Twenty-Two.

Table Twenty-Two
Program Impacts by Participation Option

Option	Counts	June Avoided kW	July Avoided kW	Aug Avoided kW
Option I m w 2-8	52	1,713.5	1,797.5	2,019.0
Option I t th 2-8	39	910.0	1,012.5	992.0
Option II m w 3-6	10	293.5	393.5	298.5
Option II m w 4-7	0	0	0	0
Option II t th 3-6	0	0	0	0
Option II t th 4-7	1	20.0	20.5	19.0
Option III m t w th 3-6	8	344.5		316.5
Option III m t w th 4-7	1	31.0		30.0
Option IV m 2-8	8	264.5	384.0	290.5
Option IV w 2-8	3	182.5	273.5	275.0
Scheduled Forward totals	122	3,760	4,289	4,241
Option dispatch dispatchable	2,194	257,882.0	278,291.5	274,302.0
Grand Totals:	2,316	261,641.5	282,580.0	278,542.5

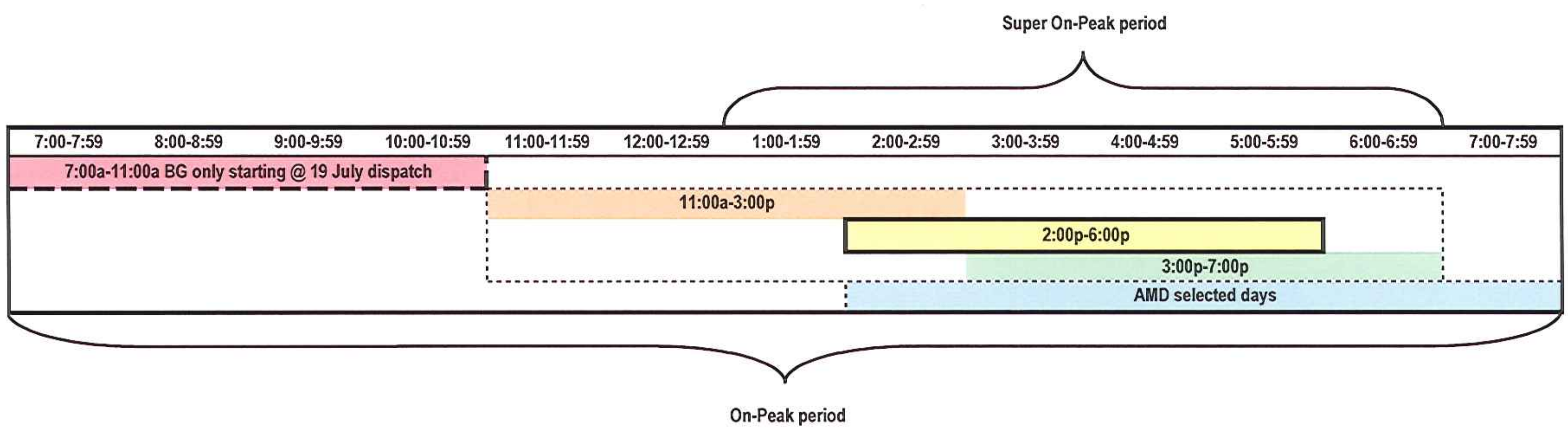
Illustration Eight, and with the exception of the Grid-Ops dispatches, depicts the four foundational dispatch blocks. Also note the specific reference to the 'super-on-peak' and 'on-peak' dispatch time horizons.

The potential avoided demand by dispatch hour associated with each of the Dispatch Events is presented in Table Twenty-Three. The values in this table are additive. That is, they represent the combination of Scheduled Forward loads plus Dispatch loads and are 'grossed-up' for the entire program[6]. In considering these data a zero (0) occasionally appears. This is due to the fact that the Scheduled Forward initiative operates Monday thru Thursday inclusive. For instance, when the Dispatch initiative was exercised on Friday the only avoided demand is that associated with Dispatch loads and none occurred after 7:00 pm on Friday.

[6] The values remain at 'site' and are NOT 'grossed-up' for T&D losses.

Illustration Eight

Dispatch Windows for Dispatch Event Scheduled Blocks & Asset Management Dispatches



Season-long hourly estimated load impacts for Schedule 72 and 72A are presented in Table Twenty-Three. The tan color-coding represents the hour and day of DEs. The blue color-coding represents Schedule Forward dispatches.

Table Twenty-Three

Hourly Estimated Load Impacts Entire 2010 Program Season

		1-Jun	2-Jun	3-Jun	4-Jun
	monday	tuesday	wednesday	thursday	friday
2:00-2:59	na	910.0	1,896.0	910.0	0.0
3:00-3:59	na	1,254.5	2,534.0	1,254.5	0.0
4:00-4:59	na	1,305.5	2,565.0	1,305.5	0.0
5:00-5:59	na	1,305.5	2,565.0	1,305.5	0.0
6:00-6:59	na	961.0	1,927.0	961.0	0.0
7:00-7:59	na	910.0	1,896.0	910.0	0.0

	7-Jun	8-Jun	9-Jun	10-Jun	11-Jun
	monday	tuesday	wednesday	thursday	friday
2:00-2:59	1,978.0	910.0	1,896.0	910.0	0.0
3:00-3:59	2,616.0	1,254.5	2,534.0	1,254.5	0.0
4:00-4:59	2,647.0	1,305.5	2,565.0	1,305.5	0.0
5:00-5:59	2,647.0	1,305.5	2,565.0	1,305.5	0.0
6:00-6:59	2,009.0	961.0	1,927.0	961.0	0.0
7:00-7:59	1,978.0	910.0	1,896.0	910.0	0.0

	14-Jun	15-Jun	16-Jun	17-Jun	18-Jun
	monday	tuesday	wednesday	thursday	friday
2:00-2:59	1,978.0	910.0	1,896.0	910.0	0.0
3:00-3:59	2,616.0	1,254.5	2,534.0	1,254.5	0.0
4:00-4:59	2,647.0	1,305.5	2,565.0	1,305.5	0.0
5:00-5:59	2,647.0	1,305.5	2,565.0	1,305.5	0.0
6:00-6:59	2,009.0	961.0	1,927.0	961.0	0.0
7:00-7:59	1,978.0	910.0	1,896.0	910.0	0.0

	21-Jun	22-Jun	23-Jun	24-Jun	25-Jun
	monday	tuesday	wednesday	thursday	friday
2:00-2:59	1,978.0	910.0	1,896.0	910.0	0.0
3:00-3:59	2,616.0	1,254.5	2,534.0	1,254.5	0.0
4:00-4:59	2,647.0	1,305.5	2,565.0	1,305.5	0.0
5:00-5:59	2,647.0	1,305.5	2,565.0	1,305.5	0.0
6:00-6:59	2,009.0	961.0	1,927.0	961.0	0.0
7:00-7:59	1,978.0	910.0	1,896.0	910.0	0.0

Table Twenty-Three (cont.)

Hourly Estimated Load Impacts Entire 2010 Program Season

	28-Jun monday	29-Jun tuesday	30-Jun wednesday	1-Jul thursday	2-Jul friday
11:00-11:59	0.0	68,325.0	0.0	0.0	0.0
12:00-12:59	0.0	68,325.0	0.0	0.0	0.0
1:00-1:59	0.0	68,325.0	0.0	0.0	0.0
2:00-2:59	1,978.0	103,897.0	1,896.0	1,012.5	0.0
3:00-3:59	2,616.0	128,880.1	2,534.0	1,388.5	0.0
4:00-4:59	2,647.0	128,931.1	2,565.0	1,440.0	0.0
5:00-5:59	2,647.0	128,931.1	2,565.0	1,440.0	0.0
6:00-6:59	2,009.0	84,299.1	1,927.0	1,064.0	0.0
7:00-7:59	1,978.0	5,371.9	1,896.0	1,012.5	0.0

	5-Jul monday	6-Jul tuesday	7-Jul wednesday	8-Jul thursday	9-Jul friday
11:00-11:59	0.0	0.0	0.0	68,325.0	0.0
12:00-12:59	0.0	0.0	0.0	68,325.0	0.0
1:00-1:59	0.0	0.0	0.0	68,325.0	0.0
2:00-2:59	2,181.5	1,012.5	2,071.0	103,999.5	0.0
3:00-3:59	2,951.0	1,388.5	2,840.5	129,014.1	0.0
4:00-4:59	2,982.0	1,440.0	2,871.5	129,065.6	0.0
5:00-5:59	2,982.0	1,440.0	2,871.5	129,065.6	0.0
6:00-6:59	2,212.5	1,064.0	2,102.0	84,402.1	0.0
7:00-7:59	2,181.5	1,012.5	2,071.0	5,474.4	0.0

	12-Jul monday	13-Jul tuesday	14-Jul wednesday	15-Jul thursday	16-Jul friday
11:00-11:59	0.0	0.0	0.0	68,325.0	68,325.0
12:00-12:59	0.0	0.0	0.0	68,325.0	68,325.0
1:00-1:59	0.0	0.0	0.0	68,325.0	68,325.0
2:00-2:59	2,181.5	1,012.5	2,071.0	103,999.5	106,254.9
3:00-3:59	2,951.0	1,388.5	2,840.5	129,014.1	130,893.6
4:00-4:59	2,982.0	1,440.0	2,871.5	129,065.6	130,893.6
5:00-5:59	2,982.0	1,440.0	2,871.5	129,065.6	130,893.6
6:00-6:59	2,212.5	1,064.0	2,102.0	84,402.1	86,606.0
7:00-7:59	2,181.5	1,012.5	2,071.0	5,474.4	9937.4

Table Twenty-Three (cont.)

Hourly Estimated Load Impacts Entire 2010 Program Season

	19-Jul monday	20-Jul tuesday	21-Jul wednesday	22-Jul thursday	23-Jul friday
7:00-7:59	18,000.0	18,000.0	0.0	0.0	0.0
8:00-8:59	18,000.0	18,000.0	0.0	0.0	0.0
9:00-9:59	18,000.0	18,000.0	0.0	0.0	0.0
10:00-10:59	18,000.0	18,000.0	0.0	0.0	0.0
11:00-11:59	43,934.8	43,934.8	0.0	0.0	0.0
12:00-12:59	43,934.8	43,934.8	0.0	0.0	0.0
1:00-1:59	43,934.8	43,934.8	0.0	0.0	0.0
2:00-2:59	82,568.0	106,495.5	2,071.0	1,012.5	0.0
3:00-3:59	128,515.3	152,049.3	2,840.5	1,388.5	0.0
4:00-4:59	128,546.3	152,100.8	2,871.5	1,440.0	0.0
5:00-5:59	128,546.3	152,100.8	2,871.5	1,440.0	0.0
6:00-6:59	84,699.3	108,647.3	2,102.0	1,064.0	0.0
7:00-7:59	9,360.4	31,423.0	2,071.0	1,012.5	0.0

	26-Jul monday	27-Jul tuesday	28-Jul wednesday	29-Jul thursday	30-Jul friday
7:00-7:59	18,000.0	0.0	0.0	0.0	0.0
8:00-8:59	18,000.0	0.0	0.0	0.0	0.0
9:00-9:59	18,000.0	0.0	0.0	0.0	0.0
10:00-10:59	18,000.0	0.0	0.0	0.0	0.0
11:00-11:59	43,934.8	0.0	0.0	0.0	0.0
12:00-12:59	43,934.8	0.0	0.0	0.0	0.0
1:00-1:59	43,934.8	0.0	0.0	0.0	0.0
2:00-2:59	82,568.0	1,012.5	2,071.0	1,012.5	0.0
3:00-3:59	128,515.3	1,388.5	2,840.5	1,388.5	0.0
4:00-4:59	128,546.3	1,440.0	2,871.5	1,440.0	0.0
5:00-5:59	128,546.3	1,440.0	2,871.5	1,440.0	0.0
6:00-6:59	84,699.3	1,064.0	2,102.0	1,064.0	0.0
7:00-7:59	9,360.4	1,012.5	2,071.0	1,012.5	0.0

Table Twenty-Three (cont.)

Hourly Estimated Load Impacts Entire 2010 Program Season

	2-Aug monday	3-Aug tuesday	4-Aug wednesday	5-Aug thursday	6-Aug friday
7:00-7:59	18,000.0	0.0	0.0	18,000.0	0.0
8:00-8:59	18,000.0	0.0	0.0	18,000.0	0.0
9:00-9:59	18,000.0	0.0	0.0	18,000.0	0.0
10:00-10:59	18,000.0	0.0	0.0	18,000.0	0.0
11:00-11:59	43,934.8	0.0	0.0	43,934.8	0.0
12:00-12:59	43,934.8	0.0	0.0	43,934.8	0.0
1:00-1:59	43,934.8	0.0	0.0	77,386.7	0.0
2:00-2:59	82,696.0	992.0	2,294.0	78,378.7	0.0
3:00-3:59	128,488.8	1,308.5	2,909.0	123,873.1	0.0
4:00-4:59	128,518.8	1,357.5	2,939.0	123,922.1	0.0
5:00-5:59	128,518.8	1,357.5	2,939.0	123,922.1	0.0
6:00-6:59	84,826.3	1,041.0	2,324.0	80,528.0	0.0
7:00-7:59	9,488.4	992.0	2,294.0	5,453.9	0.0

	9-Aug monday	10-Aug tuesday	11-Aug wednesday	12-Aug thursday	13-Aug friday
7:00-7:59	0.0	0.0	0.0	0.0	0.0
8:00-8:59	0.0	0.0	0.0	0.0	0.0
9:00-9:59	0.0	0.0	0.0	0.0	0.0
10:00-10:59	0.0	0.0	0.0	0.0	0.0
11:00-11:59	0.0	0.0	0.0	0.0	0.0
12:00-12:59	0.0	0.0	0.0	0.0	0.0
1:00-1:59	0.0	0.0	0.0	0.0	0.0
2:00-2:59	2,309.5	992.0	2,294.0	992.0	0.0
3:00-3:59	2,924.5	1,308.5	2,909.0	1,308.5	0.0
4:00-4:59	2,954.5	1,357.5	2,939.0	1,357.5	0.0
5:00-5:59	2,954.5	1,357.5	2,939.0	1,357.5	0.0
6:00-6:59	2,339.5	1,041.0	2,324.0	1,041.0	0.0
7:00-7:59	2,309.5	992.0	2,294.0	992.0	0.0

Table Twenty-Three (cont.)

Hourly Estimated Load Impacts Entire 2010 Program Season

	16-Aug monday	17-Aug tuesday	18-Aug wednesday	19-Aug thursday	20-Aug friday
7:00-7:59	0.0	0.0	0.0	0.0	0.0
8:00-8:59	0.0	0.0	0.0	0.0	0.0
9:00-9:59	0.0	0.0	0.0	0.0	0.0
10:00-10:59	0.0	0.0	0.0	0.0	0.0
11:00-11:59	0.0	0.0	0.0	0.0	0.0
12:00-12:59	0.0	0.0	0.0	0.0	0.0
1:00-1:59	0.0	0.0	0.0	0.0	0.0
2:00-2:59	2,309.5	992.0	2,294.0	992.0	0.0
3:00-3:59	2,924.5	1,308.5	2,909.0	1,308.5	0.0
4:00-4:59	2,954.5	1,357.5	2,939.0	1,357.5	0.0
5:00-5:59	2,954.5	1,357.5	2,939.0	1,357.5	0.0
6:00-6:59	2,339.5	1,041.0	2,324.0	1,041.0	0.0
7:00-7:59	2,309.5	992.0	2,294.0	992.0	0.0

	23-Aug monday	24-Aug tuesday	25-Aug wednesday	26-Aug thursday	27-Aug friday
7:00-7:59	0.0	18,000.0	0.0	18,000.0	0.0
8:00-8:59	0.0	18,000.0	0.0	18,000.0	0.0
9:00-9:59	0.0	18,000.0	0.0	18,000.0	0.0
10:00-10:59	0.0	18,000.0	0.0	18,000.0	0.0
11:00-11:59	0.0	43,934.8	0.0	43,934.8	0.0
12:00-12:59	0.0	43,934.8	0.0	43,934.8	0.0
1:00-1:59	0.0	43,934.8	0.0	43,934.8	0.0
2:00-2:59	2,309.5	88,004.3	2,294.0	88,004.3	0.0
3:00-3:59	2,924.5	133,498.6	2,909.0	133,498.6	0.0
4:00-4:59	2,954.5	133,547.6	2,939.0	133,547.6	0.0
5:00-5:59	2,954.5	133,547.6	2,939.0	133,547.6	0.0
6:00-6:59	2,339.5	90,153.6	2,324.0	90,153.6	0.0
7:00-7:59	2,309.5	992.0	2,294.0	992.0	0.0

Table Twenty-Three (cont.)

Hourly Estimated Load Impacts Entire 2010 Program Season

	30-Aug monday	31-Aug tuesday
7:00-7:59	0.0	0.0
8:00-8:59	0.0	0.0
9:00-9:59	0.0	0.0
10:00-10:59	0.0	0.0
11:00-11:59	0.0	0.0
12:00-12:59	0.0	0.0
1:00-1:59	0.0	0.0
2:00-2:59	2,309.5	992.0
3:00-3:59	2,924.5	1,308.5
4:00-4:59	2,954.5	1,357.5
5:00-5:59	2,954.5	1,357.5
6:00-6:59	2,339.5	1,041.0
7:00-7:59	2,309.5	992.0

Load profile data impact analysis

Throughout the control period, Company SCADA data were collected and used in preparing estimated impact analyses. Attachment One includes 60s SCADA data for each of the following five transmission substations on each of the dispatch event days: (1) Amps; (2) Big Grassy; (3) Rigby; (4) Bonneville and (5) Jefferson. The impact of load dispatches is dramatic and unequivocal. The magnitude of the first half of June loads is significantly less than previous seasons. Further analysis suggests that the maturing of field crops and the 2nd cutting for alfalfa hay have a predictable impact on reducing loads post August 1st.

Cost-effectiveness analyses

Cost-effectiveness calculations were prepared for each of the four standard utility industry tests in a manner consistent with the methodologies described earlier. In this evaluation, however, full program costs for both Schedule 72 and Schedule 72A together with benefits from both program components are used as the basis for the evaluations. Benefits and costs for Schedule 72 and 72A upon which calculations are prepared are presented in Table Twenty-Four below[7].

Table Twenty-Four

2010 Benefit / Cost Categories & Values–Schedules 72 & 72A

Cost Categories	Cost Values	Benefit Category	Benefit Value
Administrative support	$0.0	$/kW-yr avoided	$73.09/kW
Program evaluation	$11,758.00		
Field / Equip / Db admin. expenses	$3,801,022.87		
Participation credits	$8,101,480.75		
Program management	$117,518.03		
Total	$12,031,779.65		
All-in $/kW program costs[8]	$42.58	Total kW	282,580*

*Total max nominal load for July

As shown in Table Twenty-Five, the combined initiatives (Schedule 72 + Schedule 72A) pass the TRC, Utility and Ratepayer Tests. The Program also passes the Participant Test. However, since the participant incurs no costs the benefit/cost ratio would be infinite. Accordingly and for the Participant Test the value is indicated as 'N/A' in the Benefit/Cost Ratio column.

[7] All program costs (both Scheduled Forward and Dispatch program components) have been included in this table.

[8] This is a rudimentary calculation simply performed by dividing all program costs by the monthly max (July) avoided demand.

Table Twenty-Five

2010 Cost-effectiveness Analyses

Test	Benefits	Costs	Net Benefits	Benefit/Cost Ratio
TRC	$21,653,300.86	$3,930,298.90	$17,723,001.96	5.51
Utility	$21,653,300.86	$12,031,779.65	$9,621,521.21	1.80
Ratepayer	$21,653,300.86	$12,031,779.65	$9,621,521.21	1.80
Participant	$8,101,480.75	$0.00	$8,101,480.75	N/A

Conclusions

Grid characteristics and associated distribution of program loads

- Altogether, the load on the five transmission substations monitored comprises ~77.9% of the total irrigation load control participating load.
- With the exception of the Rigby Transmission Substation there is virtually no load diversity on the four transmission substations–(1) Amps; (2) Big Grassy; (3) Jefferson and (4) Bonneville.
- Of the five transmission substations monitored–((1) Amps; (2) Big Grassy; (3) Jefferson, (4) Rigby and (5) Bonneville) there is a total of 336 MW. Of that total, irrigation load represents 295MW or 88%.
- Irrigation Load Control Program participation on the five monitored transmission substations totals to 220MW or 75% of the total available irrigation load and 65% of the total load.
- 66 of the 90 circuits (or 73% of the circuits) fed by one of the five transmission substations have irrigation loads that represent ≥85% of the total load on that circuit
- 55 of the 90 circuits (or 61% of the circuits) fed by one of the five transmission substations have irrigation loads that represent ≥95% of the total load on that circuit

The above data make it more than clear that *DE's must absolutely be executed in an intelligent fashion.*

Grower perception considerations

- The 2010 *Dispatch stair-stepping initiative was positively received* by the growers with no indication from growers that either row or field crops were adversely affected by quality or yield impacts
- Key to program success is maintaining a local presence of agri-irrigation / information systems specialists and irrigation equipment / agri-electrician specialists.
- The 2010 season represented the 8th consecutive season where no complaints have been issued to either the Commission or to the Company. Local C & CM staff and field teams have been required and are motivated to a customer service approach to solving problems coincident to when the problem presents itself. This approach is viewed and valued as a risk mitigation strategy and ultimately minimizes program and Company costs.

- Throughout the 2010 season additional growers began to actively use the remote control equipment for regular irrigation turns. That said, there has been and remains a variety of interesting technical issues and operational considerations that require additional attentions to ensure system robustness.

The principle issues that blunt further program effectiveness center on equipment reliability and program size, which impacts program realization during any particular hour needed.

Change considerations

- Growers perceived the stair-stepping of loads into and out-of dispatch events along with minimizing loads that could be removed at any one time had a positive effect on pump motors.
- The stair-stepping effort was and is the precursor to a 'smart-grid'. Successful further utilization of Irrigation Load Control to achieve the benefits of 'smart-grid' will require a continued cooperative efforts between various RMP organizations including but not limited to C & CM, Distribution Engineering, Grid-Ops, Demand Side Management, Area Planning, Commercial & Trading, Metering and Regulatory. The benefits of a 'smart-grid' approach require quantification, however.

Meteorological considerations

- From a meteorological perspective the 2010 season was relatively normal both in terms of rainfall and temperature.
- That said the first two weeks of June were wetter and cooler than normal and it had a particularly adverse effect on hay production. Moreover, field crops were late in the harvest cycle. Some fields were not harvested until September.

Recommendations

- Find a solution to the equipment reliability issue. The 2-way equipment has allowed the program to migrate to a 'dispatch' initiative. That said, making the transition has come at a price. Time, resources and budget have been consumed with simply getting and keeping the system operational. RMP is and will continue to work with the equipment vendor to remedy current equipment shortcomings and to further 'harden' the equipment for the harsh agricultural environment.
- Design dispatch protocol to extract additional value from a 'smart-grid' approach. For example, in 2010 benefit from Irrigation Load Control was provided to C&T, Grid-Ops and Area Planning. Concomitant efforts will be required to appropriate value these benefits and to assess their viability to alternative solutions.

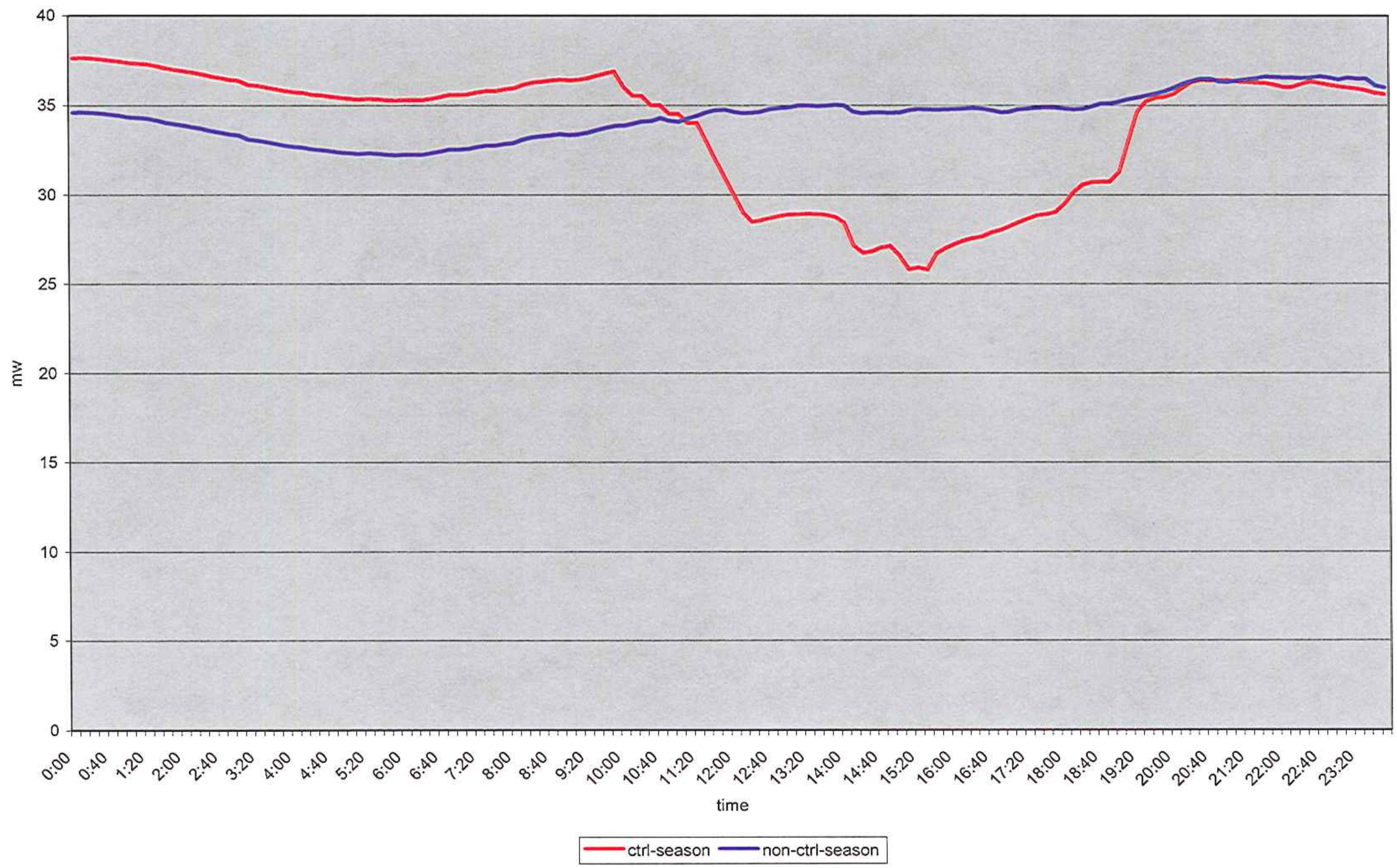
- ❖ Continue to work with individual growers and the IIPA to gain their support for the variety of requisite dispatch protocols and potential offerings that could add additional value to the Company and to the Idaho ratepayer.
- ❖ To date the Company has constructed a solution that has required creativity and innovation. From the control technology, to program design and operations a solution has been built from the ground up and at each juncture the Company has had to evolve the program solution to address new challenges. While much is behind the Irrigation Management Team, continued program evolution is anticipated to resolve technical problems and maximize the value to the Grid. Accordingly, current tariffs may require modification to accommodate the flexibility required to allow for the testing of alternative solutions, operational processes / practices.

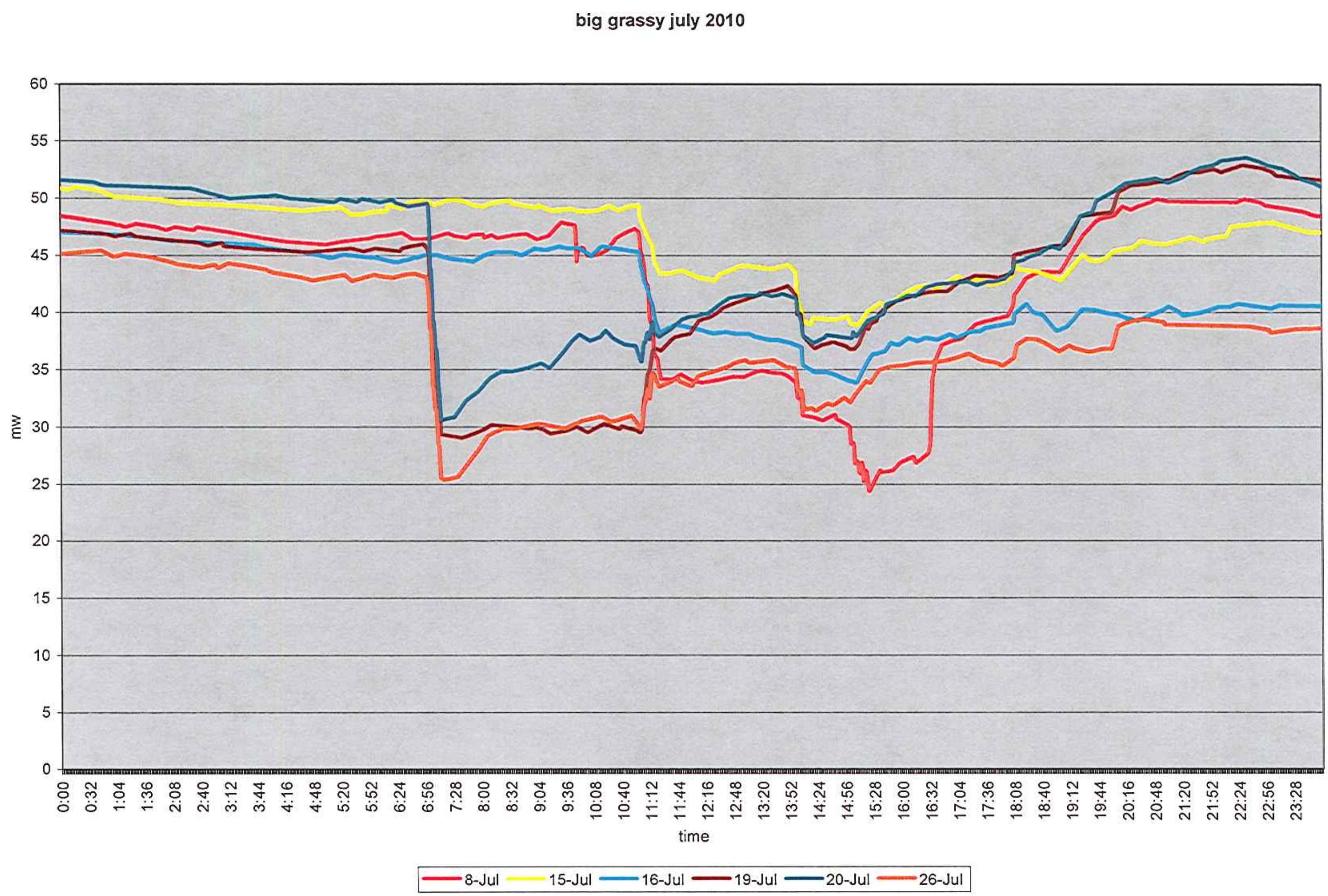
Attachment One: Rocky Mountain Power Northern Tier Transmission Substations

Geo-spatial location of transmission substations

Big Grassy Plots

big grassy (season 2010)

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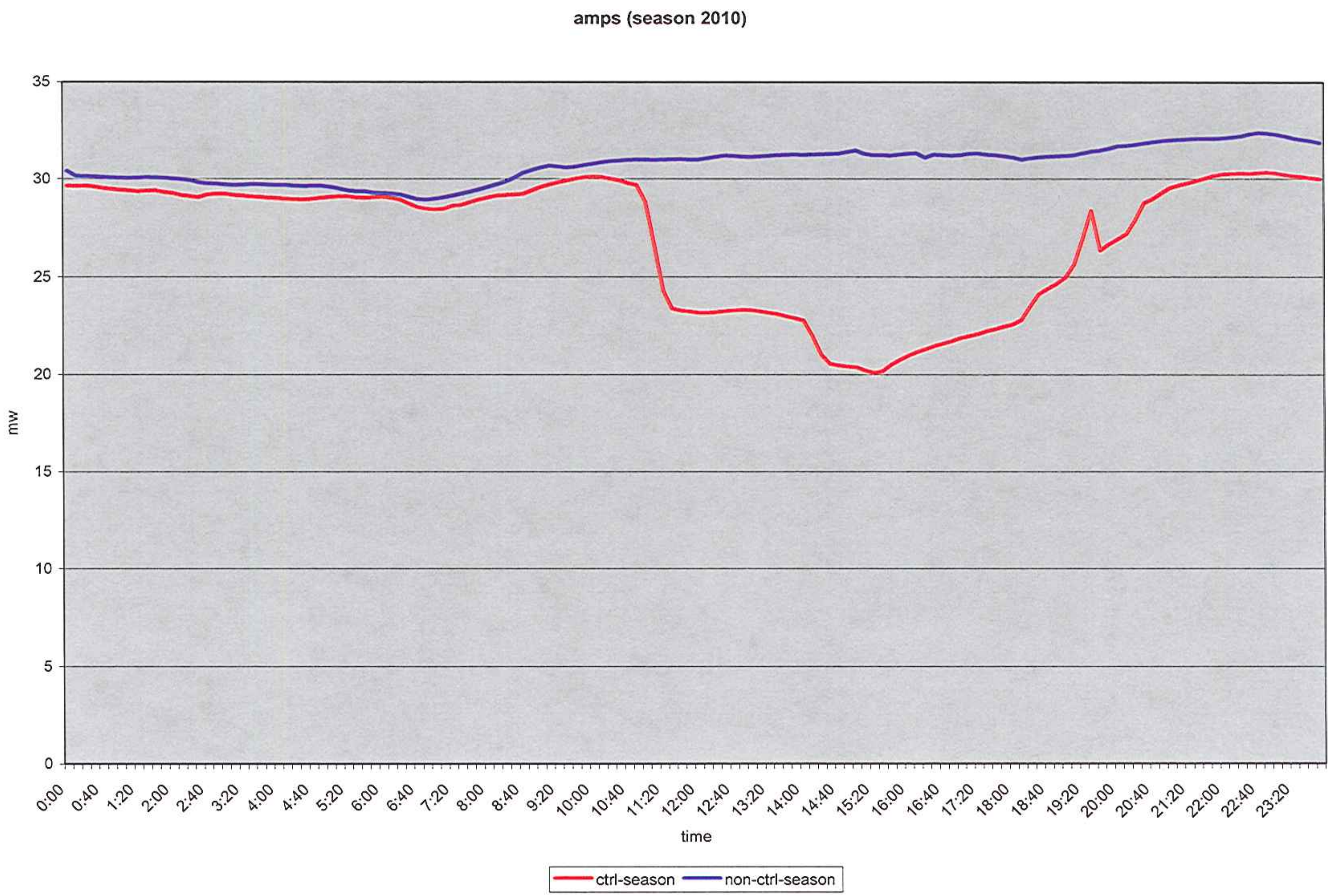
time
8-Jul
15-Jul
16-Jul
19-Jul
20-Jul
26-Jul

Amps Plots



amps (season 2010)
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time
ctrl-season
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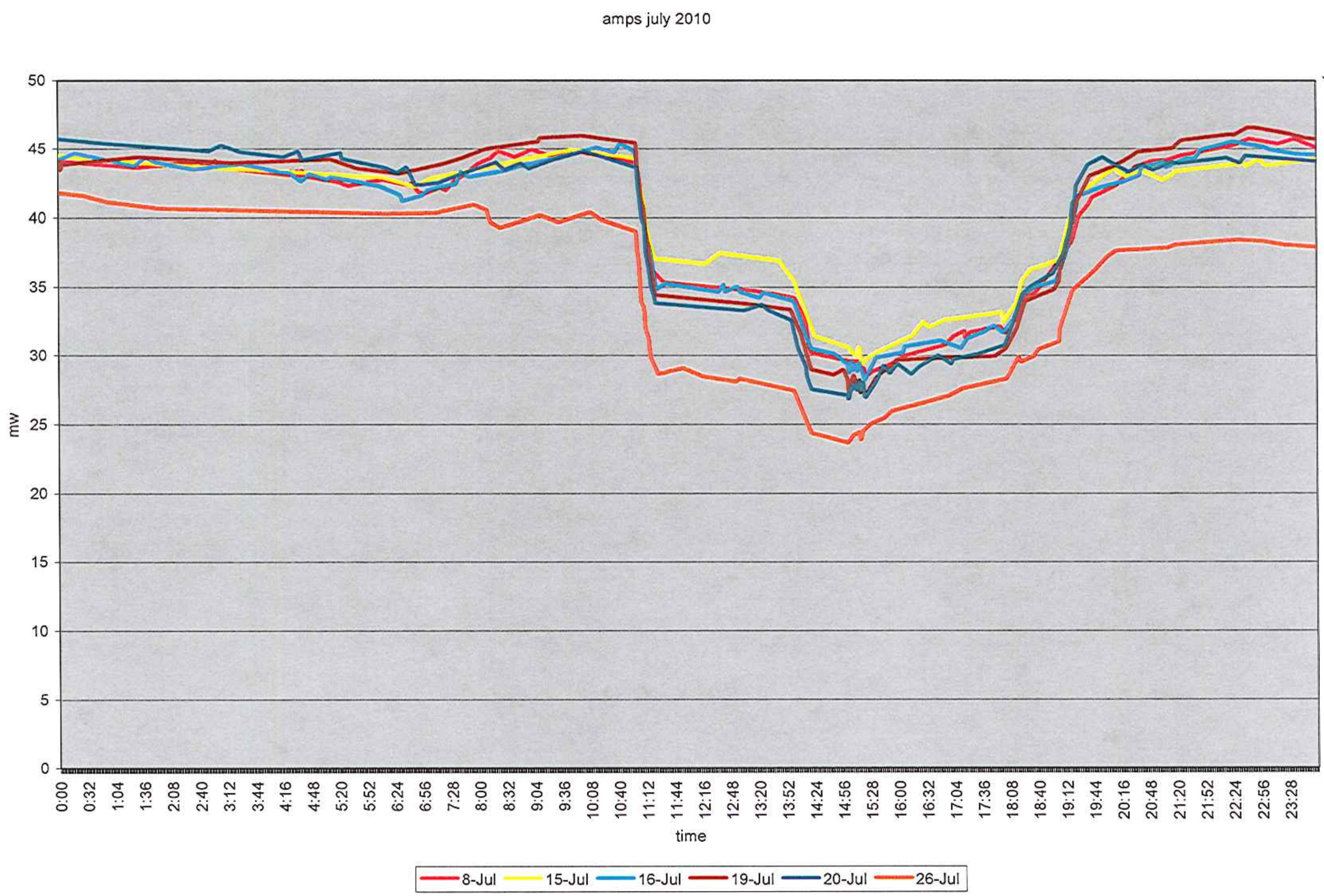
amps july 2010
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time
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15-Jul
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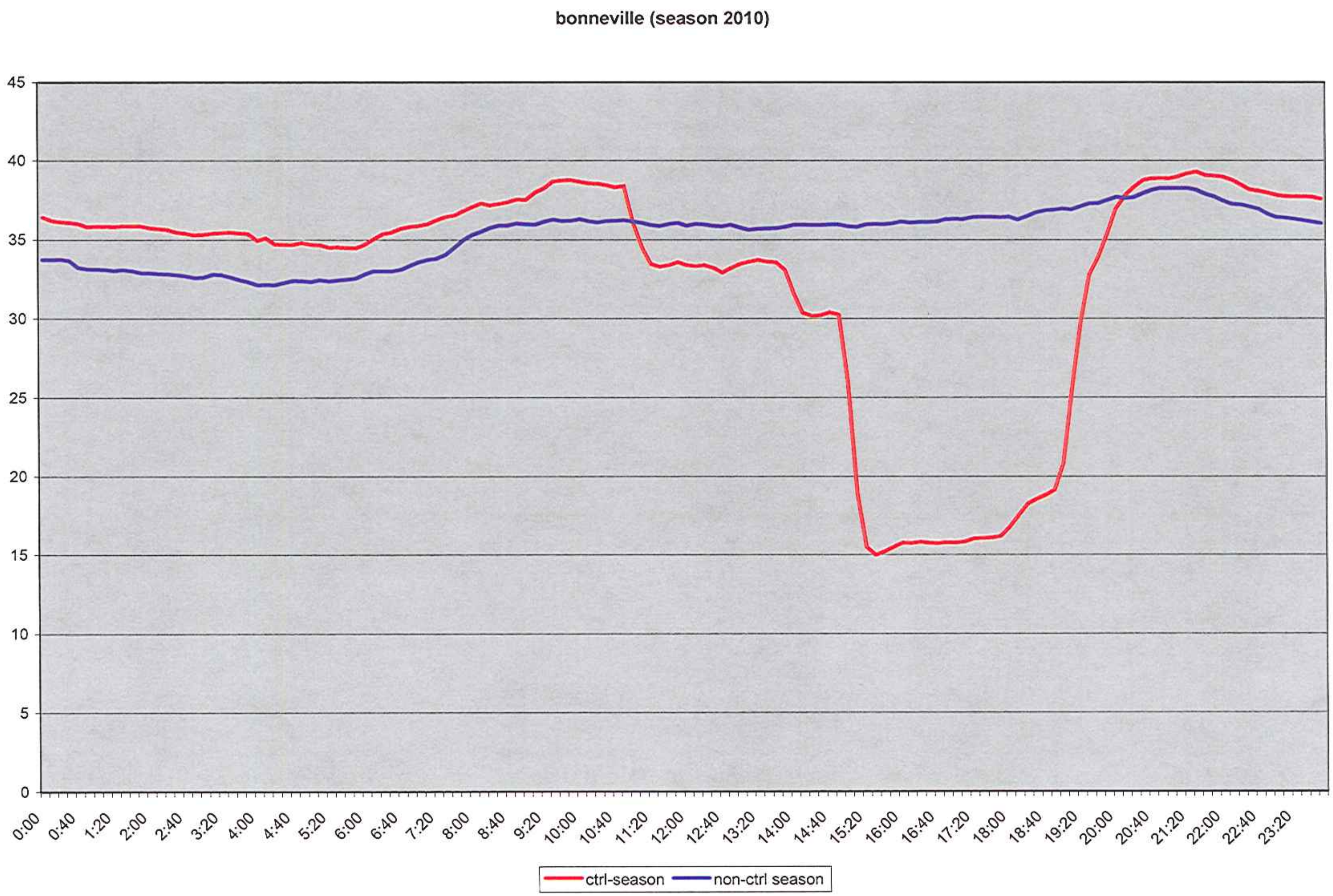
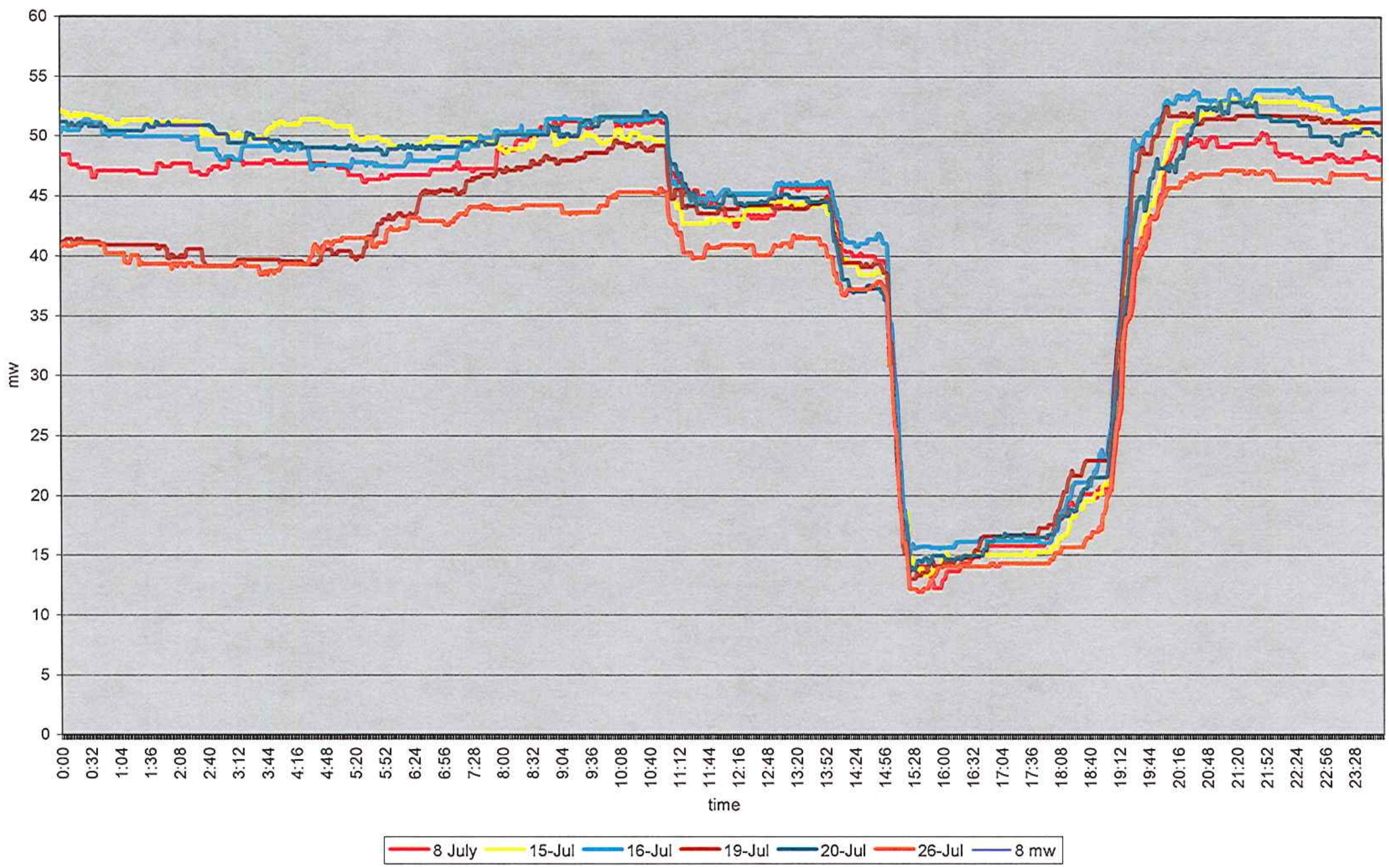
20-Jul
26-Jul

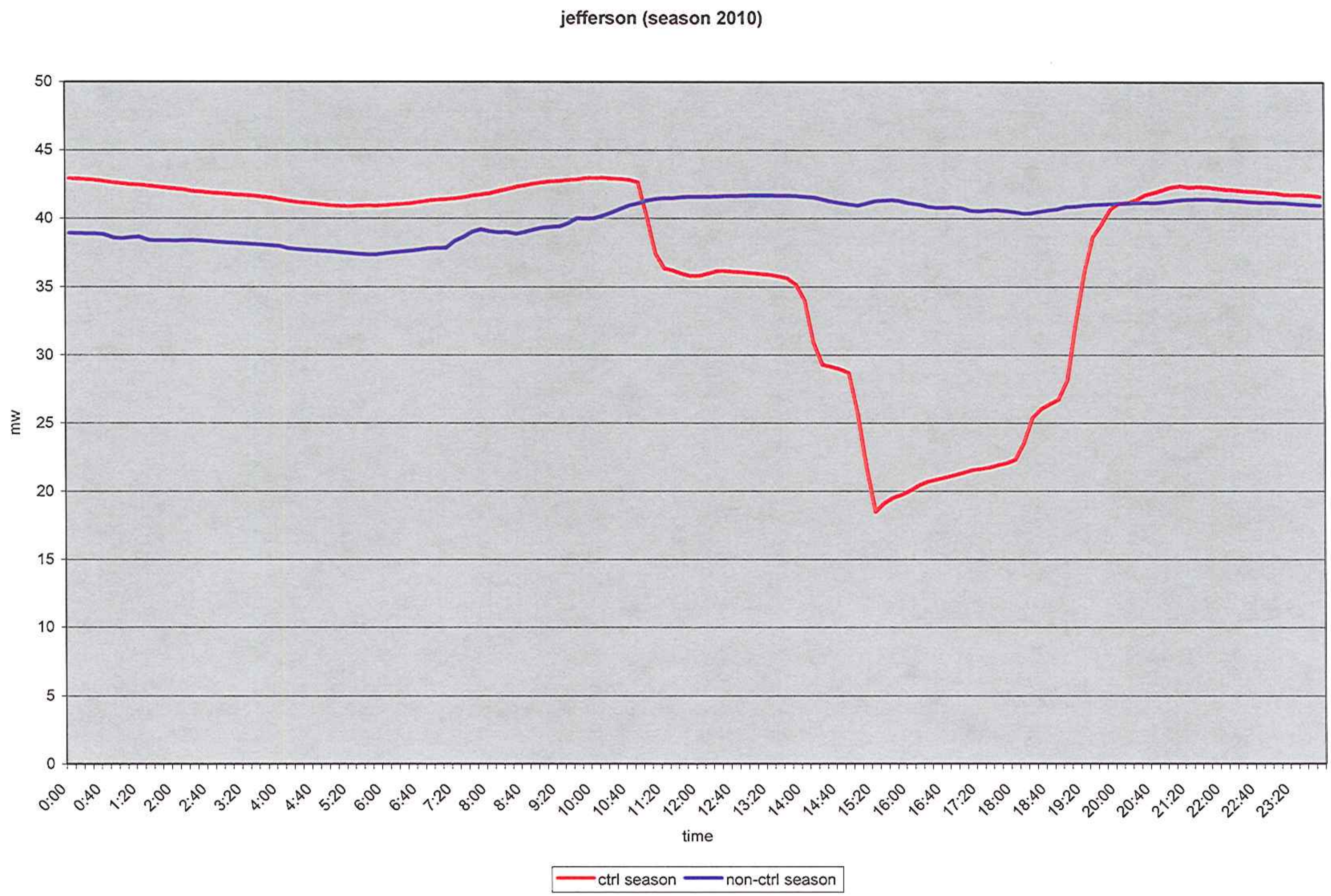
Bonneville Plots



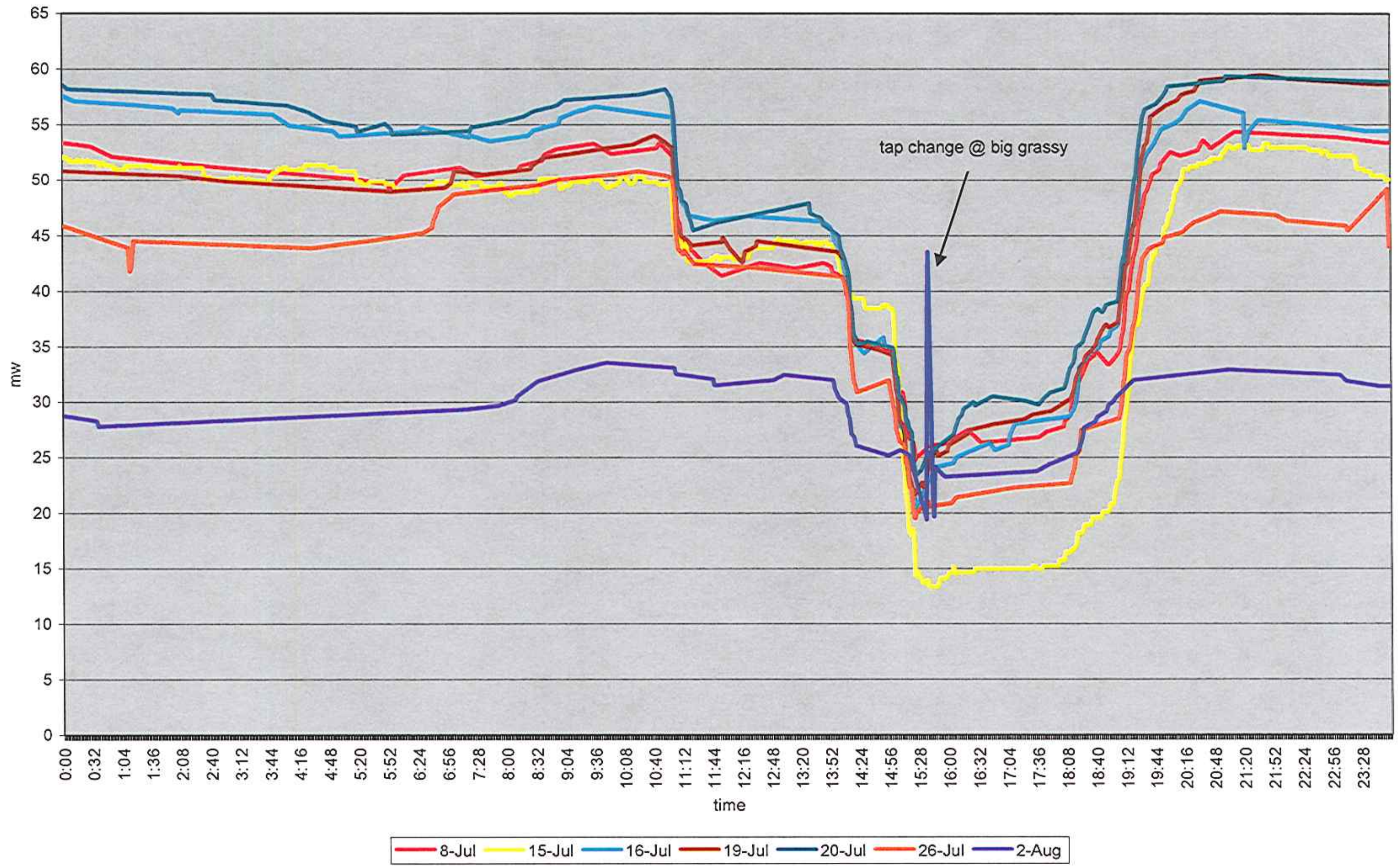
bonneville july 2010



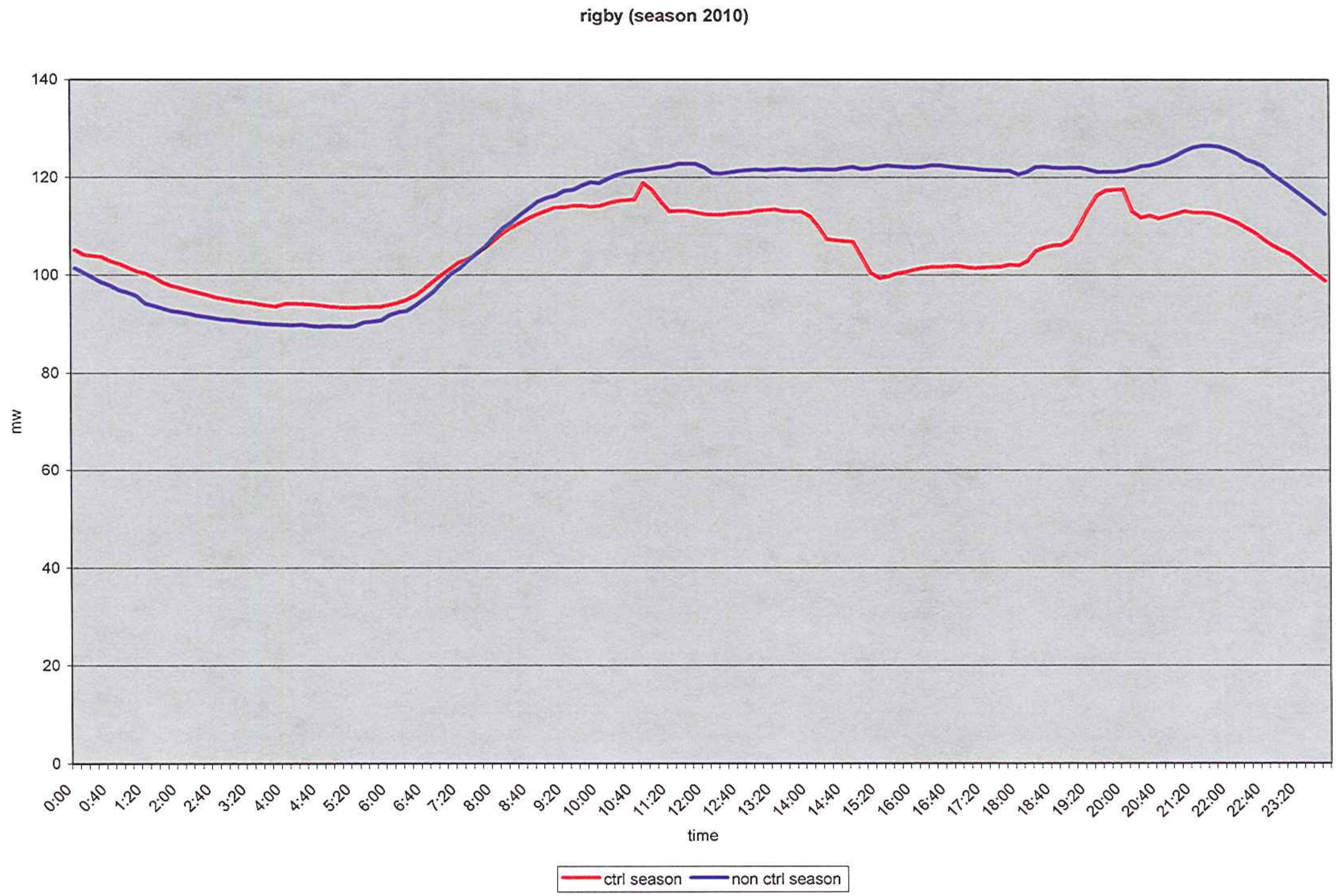
Jefferson Plots



jefferson july 2010



Rigby Plots


rigby (season 2010)
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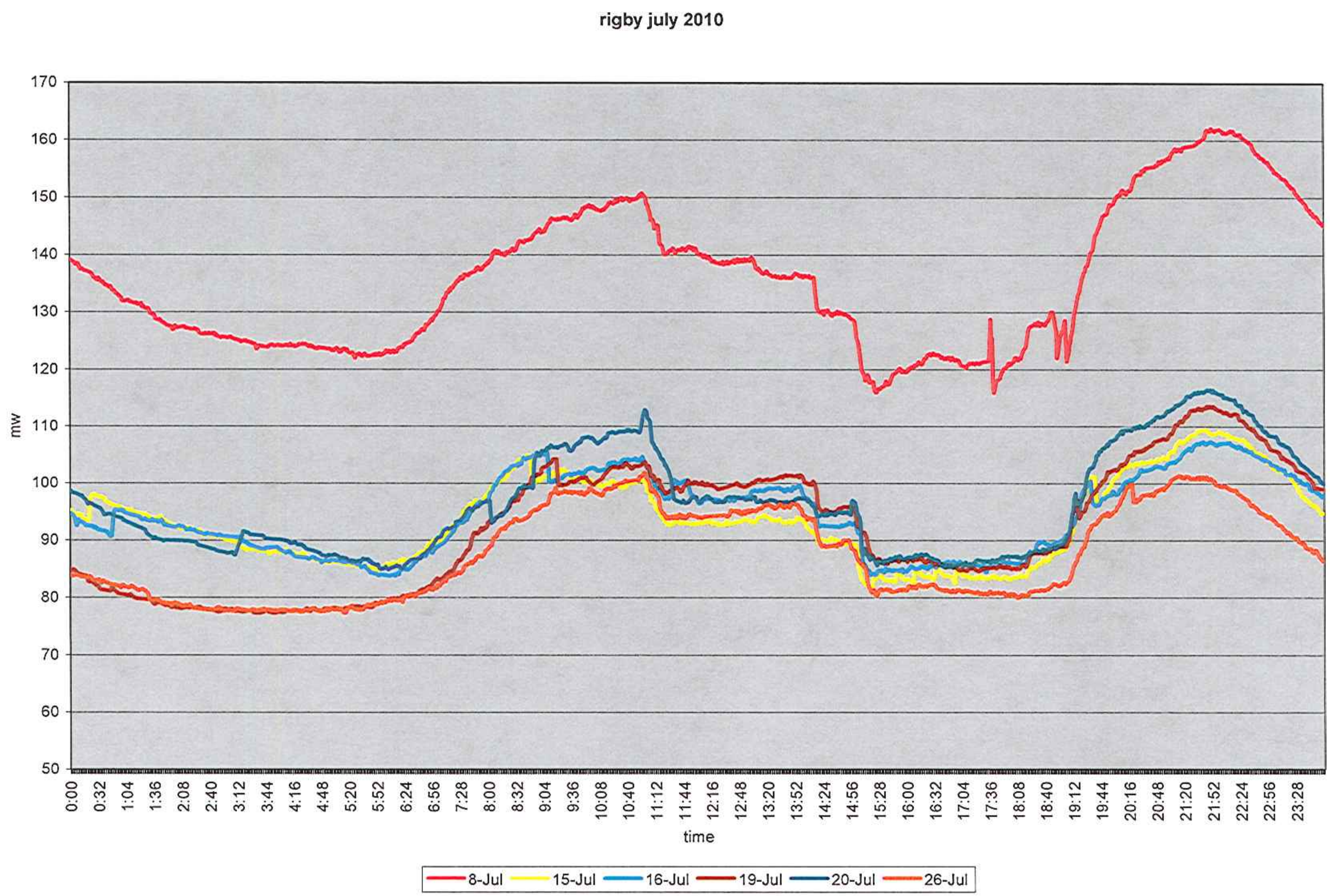
rigby july 2010
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APPENDIX 3

THE CADMUS GROUP, INC.

Date: March 24, 2011

To: Jeff Bumgarner

From: Jim Stewart, Hossein Haeri and Brian Hedman

Re: Impacts of Rocky Mountain Power's Idaho Irrigation Load Control Program

---

Rocky Mountain Power retained The Cadmus Group to evaluate the 2009 and 2010 demand impacts of the company's irrigation load control program offered to the customers in Idaho. This document summarizes the results of Cadmus's study.

Background

In 2009, the Program enrolled 2,032 customers and had approximately 260 MW of participating load in Schedule 72 (schedule forward) and Schedule 72A (option dispatch). In 2010, the Program enrolled 1,975 customers and had approximately 283 MW of participating load. In both years, over 98 percent of the Program load was enrolled through the dispatch option.

During the 2008 Program Season the Company began noticing voltage excursions outside industry acceptable standards during dispatch events. In 2010 the Company implemented a process to reduce load and return load to normal operating levels in phases to minimize the impact on the company's transmission and distribution system. As a result, the Company was still unable to take the entire participating load off during the peak time period between 2:00p and 6:00p. As a consequence, the current level of participation is beyond what RMP can effectively dispatch. This has reduced the Program's cost-effectiveness.

Technical Approach

The Cadmus Group estimated the hourly load reductions achieved by the Program in 2009 and 2010. The analysis was conducted using SCADA system data for five sub-stations (Amps, Big Grassey, Bonneville, Jefferson, and Rigby) that accounted for most (77 percent) of the controlled irrigation load in Idaho. For each substation and event hour, Cadmus estimated a reference load, what the load would have been in the absence of the event, and compared it to the observed load during curtailment events. Results were extrapolated as representative of the remaining circuits to account for total program loads.

The reference load for an event hour was estimated in two ways: (1) as the unconditional average load in the same hour of the two weekdays preceding and following the event; and (2) as the conditional average load estimated using a regression of hourly demand on weather, calendar and time effects, and indicators for event hours and hours preceding and following the event. The difference between the observed load and the actual yielded the estimate of the load reduction in the event hour.

For both estimation approaches, the estimated load reduction in each hour was compared to the expected load reduction (nominal load reduction) adjusted for opt-outs and a load reduction realization rate was calculated. There are several aspects of this methodology that are worth noting before considering the results. Nominal load is defined as the sum of customers' average billing demands for June, July and August for the two prior years.

- The impact analysis is based on SCADA data at the substation level. Since the majority of the loads being served by these substations consist of irrigation, the amount of "noise" in the data resulting from the variability of non-irrigation loads is expected to be minimal. Moreover, the hourly demand model used to estimate the load impacts largely accounts for such noise in the substation data.[1]

- Program management staggers (stair-steps) the dispatching of loads at the beginning and end of events for grid reliability purposes. The hourly analysis of loads does not account for the staggering. As a result, the estimated load impacts in the first and last hours are an estimate of the average load reduction over the hour and may not represent the true reduction at the beginning (likely to be smaller than estimated) or end of the hour (likely to be larger).

- The analysis adjusts for, in the calculation of realization rate, the required scheduling of 22 percent of the available participating loads outside of the 2:00p-6:00p time period. This scheduling restriction was implemented in 2010 to accommodate the Grid control voltage limitations previously noted. While this did not impact realization rates, it did impact the decrease in aggregate reduction from 205 MW in 2009 to 156 MW in 2010.

Results Summary and Conclusions

With these limitations in mind, the evaluation team analyzed the substation data for the 2:00p to 6:00p time horizon and reached the following conclusions:

- In 2009, the maximum hourly load reduction on the five substations was 158 MW which extrapolates to 205 MW for the entire program. This reduction occurred on July 17 and represented 86 percent of the nominal load (program resources) adjusted for opt-outs in the hour. The realization rates, which show how much load was shed relative to expectation, ranged from a low of 17 percent on August 5 to the July 17 high of 86 percent. In 2010, the maximum hourly load reduction at the five substations was 120

[1] Of the five substations only the Rigby substation serves other loads, including small businesses, a college, a hospital and the cities of Rexburg, Rigby, Ririe, Menan, and smaller towns.

MW which extrapolates to 156 MW for all Idaho irrigation program loads. This occurred on July 8 and represented 77 percent of the opt-out-adjusted nominal load in the hour. Program benefits are calculated based on 156 MW of system impact. On July 20, a load reduction of 120 MW resulted in the maximum realization rate of 82 percent. During hours when events are traditionally called, realization rates ranged from a low of 29 percent on August 24 to the high of 82 percent on July 20.

- Realization rates were calculated based on expected loads, or in the case of the Rocky Mountain Program, loads that could safely be dispatched without adversely impacting line voltages. This is an important distinction worth noting. Had the calculation of realization rates been based on total participating loads, this would have resulted in lower realization rates. As program cost-effectiveness is calculated on actual load reductions relative to a program's costs (rather than a realization rate), realizations rates should not be considered the definitive measurement of a program's effectiveness and value.
- The load reductions and realization rates in any year may not be representative of typical load impacts the program might achieve because of annual weather-related variations in irrigation demand.
- Rocky Mountain Power system peak coincides with hours when events are traditionally called (hours 2:00p to 6:00p). In 2009, all of the top 10 non-event, summer hours occurred during the traditional event window. Rocky Mountain Power system peak hours do not coincide with morning and early afternoon / evening hours when loads were dispatched in 2010 because of transmission and distribution constraints.
- While the Program has been operationally effective, it has not been as cost-effective as it could be. In 2009 and 2010, the Program enrolled more load on some substations than it could dispatch during peak hours because of transmission and distribution constraints. To increase future cost-effectiveness, RMP needs to either upgrade its transmission and distribution system in Idaho to remove the operating constraints or limit enrollment in the Program to a level consistent with the system's ability to dispatch resources during peak hours.

In addition, since the inception of the program Rocky Mountain Power has been educating irrigators about efficient irrigation practices and the benefits of irrigating during off-peak hours. Rocky Mountain Power estimates that because of education irrigators have shifted between 5 and 7 percent of their loads between 2:00p and 6:00p to off peak. The estimation of the reference load for this analysis is not taken into consideration in this analysis. If the benefits from education were taken into consideration the load shifting from education would have the effect of further improving measured impact or realization rate.

Objectives

The objectives of this evaluation were:

- To estimate the irrigation load reductions from Rocky Mountain Power's irrigation direct load control program in 2009 and 2010.
- To estimate *ex-post* realization rates, the ratio of the *ex-post* impacts to the nominal program loads that can be shed.

Program Operations

RMP operates two irrigation load control programs in Idaho. The first is "schedule forward" (Schedule 72) and involves direct control of irrigation loads on a scheduled basis. Enrollment in this program has been decreasing annually with the implementation of the dispatch program option. In July 2009, there were 4.1 MWs of nominal load in this program. The second is the dispatch option (Schedule 72a). RMP calls "events" with 24 hours advance notice and uses simplex technology to shed irrigation loads during event hours (a maximum of four hours per day per customer during weekdays).[2] The event hours are typically between 2:00p to 6:00p. In July of 2009, there were 254 MWs of nominal irrigation load in both programs. In July of 2010, there were 282 MWs of nominal load.

Event History

In 2009, RMP called six events that each lasted four hours. The events occurred between 2:00p and 6:00p. Table 1 shows the dates and hours of the events.

Table 1. Event Days and Hours in 2009

Idaho 2009	
30-Jun	4 hours
17-Jul	4 hours
23-Jul	4 hours
3-Aug	4 hours
5-Aug	4 hours
13-Aug	4 hours
Hours for all events occurred during hours 2:00p to 6:00p.	

In 2010, RMP called 11 events, excluding three one-hour events in early June and one four-hour event for irrigators served by the Big Grassey substation and for grid operations purposes.[3] In addition to a larger number of events in 2010, there were also a larger number of hours when

[2] Participants may opt out of a maximum of five events per season.

[3] The regression models control for the grid operations events, but we do not report the estimated load reductions.

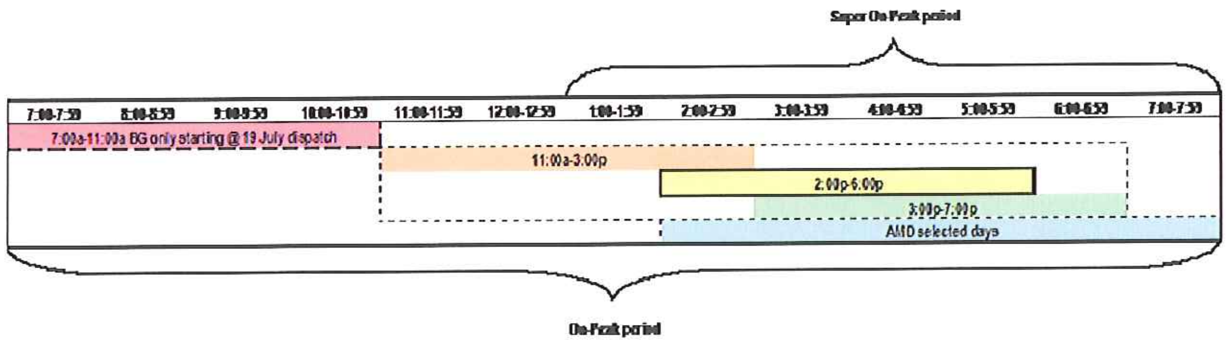
RMP dispatched program resources. Resources were dispatched during not just 2:00p-6:00p but also hours before and after this window because of transmission and distribution constraints. Table 2 shows the dates and number of hours for the 2010 events.

Table 2. Event Days and Hours in 2010

Idaho 2010	
29-Jun	8 hours*
8-Jul	8 hours*
15-Jul	8 hours*
16-Jul	8 hours*
19-Jul	12 hours**
20-Jul	12 hours**
26-Jul	12 hours**
2-Aug	12 hours**
5-Aug	12 hours**
24-Aug	12 hours**
26-Aug	12 hours**
*Hours for all substations: 11:00a -7:00p. ** For all substations except Big Grassey, event hours occurred 11:00a – 7:00p. Beginning July 19, RMP also dispatched Big Grassey customer loads from 7:00a - 11:00a.	

Between the first event on June 29, 2010 and the fourth event on July 16, 2010, RMP dispatched program resources on event days in three blocks over eight hours: 11:00a –3:00p, 2:00p – 6:00p, and 3:00p–7:00p. Figure 1 illustrates the dispatch of program resources during these time blocks.

Figure 1. Summer 2010 Irrigation Direct Load Control Dispatch Blocks



Beginning with the fifth event on July 19 and ending with the final (11th) event on August 26, RMP dispatched additional resources between 7 am and 11 am on the Big Grassey substation.[4] Resources associated with the other substations continued to be dispatched in three blocks between 11:00a and 7:00p.

Tables 3 and 4 show loads at the five substations that RMP expected it could shed during each month of 2009 and 2010 based on the historical demand of enrolled customers. This is known as the 'nominal' load. The estimates of nominal load in Tables 3 and 4 do not take into account customers that opted out of events.

In 2009, the nominal load varied across months but not hours, as all available program resources were dispatched during the 2:00p – 6:00p window. Nominal loads were highest during July when irrigation demand was greatest.

Table 3. Program Nominal Resources (MW) in 2009 for Five Substations

	June (all event hours)	July (all event hours)	August (all event hours)
Program Nominal Irrigation Load (MW) served by substations in estimation sample	178	196	188
Source: Table 14, Schedule 72 and 72A Idaho Irrigation Load Programs 2009 Credit Rider Initiative Final Report and personal communications with Bill Marek about percentage of program nominal load served by Amps, Big Grassey, Bonneville, Jefferson, and Rigby substations. Loads are not adjusted for opt-outs. Nominal load is the load that RMP expected it could shed based on program enrollment and transmission and distribution constraints.			

[4] In addition, there was an AMD dispatch block on Amps 3 days/week from 6:00p -12:00a. This involved a small amount of load, approximately 1.75 MW per dispatch or 5.3MW in total. All AMD dispatches from all substations accounted for ~15 MW of participating load.

In 2010, the nominal loads on the five substations varied between months and event hour, as program resources were dispatched in several four-hour blocks, as described above. The nominal loads do not take into account the gradual ramping down and up of loads at the beginning and end of the period or opt outs.

Table 4. Program Nominal Resources (MW) in 2010 for Five Substations

	7-10a	11:00a	12:00p	1:00p	2:00p	3:00p	4:00p	5:00p	6:00p	7:00p	8p-12a
June	0.0	47.0	47.0	49.0	89.3	148.8	148.8	148.8	110.1	5.8	1.6
July 1-July 19	0.0	50.7	50.7	53.0	96.5	160.7	160.7	160.7	118.9	6.2	1.8
July 20-July 31	17.1	42.6	42.6	44.9	88.4	151.7	151.7	151.7	109.9	6.2	1.8
August	16.9	42.0	42.0	44.2	87.1	149.6	149.6	149.6	108.3	6.2	1.7

Source: Schedule 72 and 72A Idaho Irrigation Load Programs 2010 Credit Rider Initiative Final Report and personal communications with Bill Marek. Loads are not adjusted for opt outs. Nominal load is the load that RMP expected it could shed based on program enrollment and transmission and distribution constraints.

Data

RMP provided Cadmus with 60 second interval data for five substations (Amps, Big Grassey, Bonneville, Jefferson, Rigby) that served irrigators in its Idaho service territory in 2009 and 2010. The substations accounted for approximately 77 percent of RMP's irrigation load subscribed in the program in Idaho in 2010. RMP also provided Cadmus with data about the days and hours when direct load control resources were dispatched.

Cadmus performed a number of quality checks on and adjustments to the interval data before analyzing the load impacts. We first put the 60 second interval data on an hourly basis by calculating average hourly loads for each substation. The hourly load data were then plotted and examined for irregularities. While the minute interval data did exhibit some random spikes and drops in load (normal perturbations in electrical Grid operations), these abnormalities were not evident after the minute interval data were averaged over the hour.

Next, we obtained hourly and daily weather data for Rexburg and Idaho Falls weather stations from the National Weather Service and merged it with the hourly load data. The weather variables in the analysis include the daily evapotranspiration rate, temperature (hourly), and rainfall (hourly).[5]

[5] The evapotranspiration rate was a weighted average of crop-specific ETRs, with weights equal to the share of land planted in the crops.

Last, Cadmus mapped information on the occurrence of load control event hours to the data. We created separate indicator variables for each hour of each event, which were included in the model.

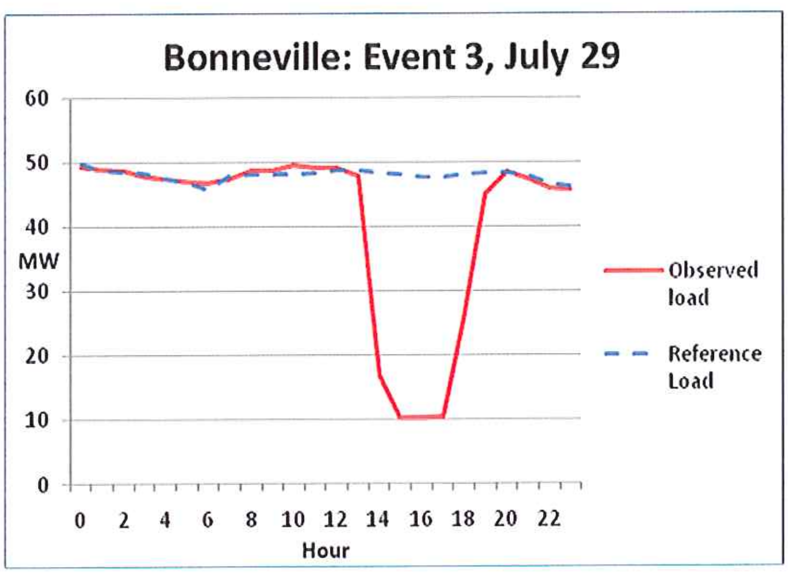
Impact Estimation Approach

The Cadmus approach to estimating the load reductions in each event was to estimate a reference load (what demand would have been in each hour of an event if the event had not occurred) in each hour during an event window. The difference between the actual load and the reference load in an event hour is the estimate of the program's impact during that event hour.

Figure 2 illustrates the approach. It shows the hourly loads for the Bonneville substation on July 23, 2009, when RMP called the third event of the summer. The event window was 2:00p to 6:00p. The red (solid) line is the observed load. The blue (dashed) line is the reference load that was generated with a regression model. The impact of the event in each hour is the difference between the metered load (red line) and the reference load (blue line). The figure depicts an estimated average hourly impact of approximately 38 MW.

The reference load can be estimated in several ways. One is a day matching approach. This involves estimating the (unconditional) average of the loads in the same hour in the two weekdays immediately preceding and following the event. If irrigation demand conditions, which are a function of weather, evapotranspiration, crop maturity, and other factors, on the reference days are similar to those on the event day, the reference load will likely represent well what demand would have been, and the difference between observed and reference loads will be an accurate estimate of the true load reduction. However, if any of the demand conditions change, the load reduction estimates will be biased.

Figure 2. Illustration of Event Impact Estimation Approach



The second approach is multivariate regression in which loads are modeled as a function of weather, time, and calendar variables. This method accounts for differences in demand conditions between event and non-event days and will generate a more accurate reference load.

Cadmus determined that because of trends in irrigation demand over the growing season that the day matching approach would not be appropriate. Reference loads were estimated using an hourly demand regression models.

Conditional Demand Impact Estimation

Using regression analysis, Cadmus also modeled hourly demand as a function of weather (evapo-transpiration, temperature, and rainfall), calendar and time effects (week of month, day of the week, and hour), and load in the same hour in the previous day.[6] The models also included separate indicator variables for each hour of each event and for each of the six hours following and preceding each event. The coefficients on the event hour variables represent the differences between the observed loads and the reference loads in the event hours. The Appendix describes the model specification in greater detail.

Cadmus estimated separate demand models for each of the substations and event months (June, July, and August). Thus, there were a total of 15 substation models (5 stations x 3 months). We estimated separate substation month models for two reasons. First, each substation has a somewhat different load shape over the summer, reflecting differences between stations in cropping practices and irrigation and non-irrigation demand.[7] Second, each substation's load shape varies significantly over the summer, reflecting changes in crop maturity, evapo-transpiration, soil-type temperature, wind, relative humidity, solar radiation, and rainfall over the growing season.

Model Estimation and Diagnostics

Cadmus estimated the models by Generalized Least Squares (GLS) under the assumption of auto-correlated errors, that is, load in each hour is assumed to be correlated with the load during a preceding hour. The error term was modeled as an autoregressive process with lag one.

We performed a number of tests to evaluate the predictive ability of the substation regression models. These tests included inspection of the signs and statistical significance of the models' coefficients, estimation of overall explanatory power of each model, represented by R^2 statistic,

[6] Loads were modeled as a function of the average temperature in the preceding 24 hours, total rainfall in the preceding 24 hours, and average daily evapo-transpiration over the preceding three days. The week of month variables capture changes in irrigation demand related to changes in cropping activities. The days of the week and hour of the day variables capture irrigation demand that varies by day and hour.

[7] The Rigby substation is different from the other stations in that it has significant non-irrigation loads.

and tests of the predictive ability of the models in hours when events could have been called on non-event days.[8] We used the results of the tests in selecting the final model specifications.

The models predict accurately what loads would have been in hours when events were not but could have been called. Table 6 reports the median absolute percentage error, the median of the percentage difference between the observed load and the load predicted by the model (|kW-model predicted kW)|/kW, during non-event hours on July weekdays between 2 and 6 pm.

Table 6. Median Absolute Percentage Error for July 2009

Hour	Amps	Big Grassey	Bonneville	Jefferson	Rigby
2:00 PM	0.74%	1.45%	1.35%	1.54%	0.72%
3:00 PM	0.86%	1.44%	1.28%	1.48%	0.67%
4:00 PM	1.62%	1.29%	0.87%	1.28%	0.64%
5:00 PM	0.95%	1.04%	1.09%	1.85%	0.67%
Note: Absolute percent error is =|predicted MW – actual MW|/ actual MW.					

For example, in 50 percent of the 3 pm non-event hours at the Bonneville station, the regression model predicts a load that is within 1.28 percent of the actual load. The median absolute prediction error ranges from less than 0.7 percent to just below two percent. Fifty percent (N=10) of the substation-hour median percentage errors are less 1.2 percent.

Estimated Load Reductions in 2009

Table 7 reports an estimate of the total load reduction for the Amps, Big Grassey, Bonneville, Jefferson, and Rigby substations and all Idaho irrigation in each event hour during summer 2009.[9] The estimate for Idaho was obtained by dividing the substation estimate by the substation percentage of the Idaho irrigation load (77 percent). The Table also reports the realization rate for each event hour (2:00p-6:00p time window), which is the ratio of the estimated total load reduction in a given hour to the nominal load adjusted for irrigation loads that opted out of the event.[10] The realization rate is a function of the estimated load reduction (the numerator) and expectations about loads that can be shed (the denominator). It may be less than or equal to 100 percent depending on technical performance of the control equipment (i.e., signals and transmitted and received and pumps are shut off) and whether irrigation demand during the season was less than or greater than expected.

[8] In general, the coefficients of the models have the expected signs and are statistically significant. Loads were increasing in the evapo-transpiration rate and temperature and decreasing in rainfall. Loads were generally highest during the afternoon and early evening hours. Also, based on their R^2 statistics, the models explain a large percentage of the variation in irrigation loads.

[9] The Appendix contains estimates of the reduction in load at the substation level in each event hour.

[10] Cadmus adjusted the nominal load for an event by subtracting the amount of load that opted out the event.

Table 7. Estimated Load Reductions and Realization Rates in 2009

Date	Event	Hour	Estimated Load Reduction - Five substations (MW)	Estimated Load Reduction - All Idaho Irrigation (MW)	Hourly Opt-Out Adjusted Realization Rate
30-Jun	Event 1	Hour 1	-41.8	-54.3	24.8%
		Hour 2	-71.8	-93.2	42.6%
		Hour 3	-70.7	-91.8	42.0%
		Hour 4	-66.4	-86.3	39.5%
17-Jul	Event 2	Hour 1	-111.1	-144.3	60.8%
		Hour 2	-157.8	-204.9	86.3%
		Hour 3	-158.0	-205.2	86.4%
		Hour 4	-151.6	-196.9	82.9%
23-Jul	Event 3	Hour 1	-102.4	-133.0	55.7%
		Hour 2	-137.7	-178.9	74.9%
		Hour 3	-138.6	-180.0	75.3%
		Hour 4	-136.5	-177.2	74.2%
3-Aug	Event 4	Hour 1	-33.6	-43.6	18.5%
		Hour 2	-50.0	-65.0	27.6%
		Hour 3	-48.1	-62.5	26.5%
		Hour 4	-48.0	-62.4	26.5%
5-Aug	Event 5	Hour 1	-30.8	-40.0	17.0%
		Hour 2	-50.0	-65.0	27.6%
		Hour 3	-49.0	-63.7	27.1%
		Hour 4	-47.4	-61.6	26.2%
13-Aug	Event 6	Hour 1	-36.6	-47.6	19.9%
		Hour 2	-45.9	-59.6	24.9%
		Hour 3	-45.4	-58.9	24.6%
		Hour 4	-45.6	-59.2	24.7%

Notes: Estimates of load reductions for 5 substations based on regression model. Estimated load reductions for all Idaho Irrigation estimated as 5 substation load reduction divided by 0.77. Realization rate is the ratio of the estimated load reduction to the opt-out adjusted nominal load.

The Program reduced irrigation loads in each event hour. The estimated load reductions ranged from -158 MW to -31 MW and were different from zero at the 5 percent significance level.[11] The estimated reductions in Idaho irrigation loads ranged from 40 MW to 205 MW. The

[11] The Appendix contains estimated confidence intervals for the estimated load reductions in all event hours.

estimates also exhibit the expected patterns. First, during each event, the estimated load reduction in the first hour was the smallest, consistent with the staggering of the event initiation for grid reliability. (During hours two, three, and four, there is very little difference in the estimated load reductions.) Second, the load reductions over the summer reflected the seasonal pattern of irrigation demand. The load reductions were largest in July, when loads and irrigation demand were at their peak. The maximum load reductions on the five substations of 158 MW and in Idaho irrigation loads of 205 MW were achieved on July 17 (event 2) during event hour 3. The estimated load reductions were significantly smaller in June and August, when irrigation demand was much lower.

The realization rates, which show how much load was shed relative to expectation in any given hour, ranged from a low of 17 percent during hour 1 of event 5 to a high of 86 percent during hour 3 of Event 2. As expected, realization rates were significantly higher in July than in June or August because of irrigation practices and crop maturity. Nominal loads were not adjusted downward to reflect the lower irrigation demand in June and August. Hence, the low realization rates were due not to Program performance but rather to below average irrigation demand and the fact that nominal rates during June and August are lower. RMP may want to consider adjusting its estimates of nominal loads to reflect changes in irrigation demand.

Estimated Load Reductions in 2010

During events in 2010, program resources were dispatched in three or four blocks over 8 or 12 hours. Loads were dispatched outside of the 2:00p to 6:00p window because of potential adverse impacts on the transmission and distribution system. Table 8 reports an estimate of the maximum hourly load reduction in each block of each event during summer 2010.[12] Cadmus reports the maximum in each block of hours instead of in each hour because of the large number of event hours. The load reductions cover the Amps, Big Grassey, Bonneville, Jefferson, and Rigby substations. It should be noted that loads that were shed between 7:00a and 10:00a or 11:00a and 1:00p resumed at the end of the event, leaving less opportunity for load reductions in subsequent hours (note: loads that were were controlled between 7:00a and 10:00a and 11:00a and 1:00p resumed at the end of the event, leaving less opportunity for load reductions in subsequent hours).

The load impacts were greatest during 2:00p – 6:00p, when most Schedule 72a resources were dispatched (see Table 4). The maximum hourly load reduction occurred on July 8, when irrigation loads on the five substations were reduced by approximately 120 MW and the Idaho irrigation load was reduced by 156 MW. Load impacts were smaller in June and August, when irrigation demand was lower.

[12] The Appendix contains estimates of the load reduction in each event hour.

Table 8. Estimated Load Reductions in 2010

Date	Event	Load	7 AM - 10 AM	11 AM - 1 PM	2 PM - 5 PM	6 PM
29-Jun	Event 1	5 Substations	N/A	-34.8	-87.0	-61.7
		All ID Irrigation	N/A	-45.2	-113.0	-80.1
8-Jul	Event 2	5 Substations	N/A	-49.6	-119.8	-85.7
		All ID Irrigation	N/A	-64.4	-155.5	-111.3
15-Jul	Event 3	5 Substations	N/A	-44.2	-107.0	-86.6
		All ID Irrigation	N/A	-57.4	-139.0	-112.5
16-Jul	Event 4	5 Substations	-39.9	0.0	-100.5	-77.7
		All ID Irrigation	-51.8	0.0	-130.5	-101.0
19-Jul	Event 5	5 Substations	-40.2	-17.9	-103.1	-83.3
		All ID Irrigation	-52.2	-23.2	-133.9	-108.2
20-Jul	Event 6	5 Substations	-48.3	-15.1	-105.4	-82.2
		All ID Irrigation	-62.7	-19.7	-136.9	-106.7
26-Jul	Event 7	5 Substations	-36.1	-12.2	-89.7	-75.8
		All ID Irrigation	-46.9	-15.9	-116.5	-98.4
2-Aug	Event 8	5 Substations	-2.4	-3.1	-6.7	1.3
		All ID Irrigation	-3.1	-4.0	-8.6	1.7
5-Aug	Event 9	5 Substations	-8.7	-10.0	-42.2	-31.5
		All ID Irrigation	-11.3	-12.9	-54.8	-41.0
24-Aug	Event 10	5 Substations	-25.5	-6.0	-41.3	-31.8
		All ID Irrigation	-33.2	-7.8	-53.6	-41.3
26-Aug	Event 11	5 Substations	-20.4	-2.6	-44.3	-30.6
		All ID Irrigation	-26.5	-3.4	-57.5	-39.7

Notes: Estimates of load reductions for 5 substations based on regression model. Estimated load reductions for all Idaho Irrigation estimated as 5 substation load reduction divided by 0.77. Realization rate is the ratio of the estimated load reduction to the opt-out adjusted nominal load.

The hourly MW impacts were smaller in 2010 than in 2009 because load control resources were dispatched over a larger number of hours. The dispatching of resources in the morning and early afternoon and early evening to address transmission and distribution issues meant that there was less potential to reduce loads during peak hours. To put the 2010 load impacts in perspective, Table 9 reports realization rates, the ratio of the estimated load impact to the nominal load in the hour adjusted for opt outs.[13] *The nominal loads during peak hours were smaller in 2010 than in 2009 because programs resources were dispatched before and after the 2:00p – 6:00p period. The realization rates account for the smaller amount of load that could have been shed between 2:00p and 6:00p.*

[13] The load opting out was subtracted from the nominal load for hours 2:00p – 6:00p for each event.

Table 9. Estimated Realization Rates in 2010 (Based on Nominal Capacity)

Date	Event	7 AM - 10 AM	11 AM - 1 PM	2 PM - 5 PM	6 PM
29-Jun	Event 1	N/A	71.0%	60.3%	56.0%
8-Jul	Event 2	N/A	93.7%	77.4%	72.1%
15-Jul	Event 3	N/A	83.5%	76.0%	72.9%
16-Jul	Event 4	N/A	0.0%	74.0%	70.8%
19-Jul	Event 5	234.9%	39.8%	76.7%	75.8%
20-Jul	Event 6	282.0%	33.7%	82.0%	74.8%
26-Jul	Event 7	211.3%	27.2%	63.9%	69.0%
2-Aug	Event 8	14.1%	6.9%	4.5%	-1.2%
5-Aug	Event 9	51.4%	22.5%	29.7%	29.1%
24-Aug	Event 10	151.4%	13.5%	28.6%	29.4%
26-Aug	Event 11	121.1%	6.0%	30.2%	28.2%

Notes: Realization rate is the ratio of the estimated load reduction to the opt-out adjusted nominal load. Opt out loads obtained from Schedule 72 & 72A Idaho Irrigation Load Control Programs: 2009 Credit Rider Initiative Final Report.

During hours when events are traditionally called, the realization rates ranged between 29 percent on August 24 and 82 percent on July 20.[14] (We ignore the August 2 event, as load reductions were uniformly and abnormally low.[15]) During peak irrigation demand between the first and third weeks of July, the realization rate ranged between 77 and 82 percent of nominal load. These impacts are slightly lower than but still close to those in 2009. The difference in realization rates may reflect the fact that irrigation demand in 2010 was relatively low because of cooler weather throughout the summer.

Conclusions

Rocky Mountain Power asked Cadmus to evaluate the demand impacts of its Idaho irrigation load control program. In 2010, the Program enrolled 1,975 customers and had approximately 283 MW of participating load. However, this participating load was more than RMP could dispatch during peak hours because of transmission and distribution system constraints. This has had the effect of reducing the Program's cost-effectiveness.

[14] On some event days, the maximum hourly realization rate between 7:00a and 10:00a exceeded 100 percent. This indicates that in these hours either the Program achieved significantly greater demand reductions than expected, or the nominal loads are too low,

[15] Irrigation demand is typically very low at the beginning of August when hay is harvested and water to field crops is turned off to initiate the crop maturation process prior to harvest. Accordingly, potential demand reductions are very small. However, the nominal load covers all of August and does not reflect haying and crop maturation. The small, negative demand reduction in the 6:00 p hour is statistically indistinguishable from zero.

Cadmus estimated the hourly load reductions from the Program in 2009 and 2010 using regression analysis of SCADA data from five substations in Idaho. In addition, Cadmus examined the coincidence of the program impacts with the PacifiCorp system peak demands.

There are several noteworthy aspects of the methodology:

- The impact analysis was based on SCADA data at the substation level. Since the majority of the loads being served by these substations consist of irrigation, the amount of "noise" in the data resulting from the variability of non-irrigation loads is expected to be minimal.

- The estimation methodology did not consider Rocky Mountain Power's education of irrigators about efficient irrigation practices. If the benefits from education were taken into consideration the load shifting from education would have the effect of improving measured impact or realization rate.

- The hourly analysis of loads did not account for staggering in the dispatching of loads at the beginning and end of events for grid reliability purposes. As a result, the estimated load impacts in the first and last hours are an estimate of the average load reduction over the hour and may not represent the true reduction at the beginning (likely to be smaller than estimated) or end of the hour (likely to be larger).

- In the calculation of realization rates, the analysis adjusts for the required scheduling of 22 percent of the available participating loads outside of the 2:00p-6:00p time period. This scheduling restriction was implemented in 2010 to accommodate the Grid control voltage limitations previously noted. While this did not impact hourly realization rates, it did have a significant effect on the difference between the nominal loads and the aggregated reductions achieved.

Year	Nominal Load	Aggregated Reduction
2009	260 MW	205 MW
2010	283 MW	156 MW

The analysis of substation loads showed the following:

- In 2009, the maximum hourly load reduction on the five substations was 158 MW or 205 MW for all Idaho irrigation program loads. This represented 86 percent of the nominal program resources dispatched in that hour. The realization rates, which show how much load was shed relative to expectation, ranged from a low of 17 percent on August 5 to the July 17 high of 86 percent. In 2010, the maximum hourly load reduction was 120 MW or 156 MW for all Idaho irrigation program loads. This occurred on July 8 and represented 77 percent of the opt-out-adjusted nominal load dispatched in the hour. On

July 20, a load reduction of 120 MW resulted in the maximum realization rate of 82 percent.

- Realization rates were calculated based on expected loads, or in the case of the Rocky Mountain Program, loads that could safely be dispatched without adversely impacting line voltages. This is an important distinction worth noting. Had the calculation of realization rates been based on total participating loads, this would have resulted in lower realization rates. As program cost-effectiveness is calculated on actual load reductions relative to a program's costs (rather than a realization rate), realizations rates should not be considered the definitive measurement of a program's effectiveness and value.

- The load reductions and realization rates in any year may not be representative of typical load impacts the program might achieve because of annual variations in irrigation demand.

- PacifiCorp system peak coincides with hours when events are traditionally called (hours 2:00p-5:00p).

Recommendations

While the Program has achieved significant load reductions, the cost-effective has been adversely impacted by the level of participation on a megawatt basis. As noted above, in 2009 and 2010, the Program enrolled more load on some substations than it could dispatch during peak hours because of transmission and distribution constraints. RMP could reduce enrollments to a level consistent with the system's ability to dispatch loads. Or if technically feasible, RMP could increase the Program's cost-effectiveness by upgrading the transmission and distribution system to alleviate constraints on when load can be dispatched.

Appendix

Substation Hourly Load Model

Let j=1,2..., J index the events and h=1,2..., H index hours of each event. Also, let MW_{it} be the electricity load of substation i at time (hour) t. Then (suppressing the index *i*) substation i's MW demand at time t (corresponding to a week of the month, day, and hour) can be written as:

$$MW_t = \alpha_0 + \alpha_1\ EvapTR72hour_t + \alpha_2\ temp24hour_t + \alpha_3 rainfall24hour_t + \sum_{w=1}^{3}\pi_w\ weekofmonth_{wt} + \sum_{d=1}^{6}\delta_d\ dayofweek_{dt} + \sum_{k=1}^{23}\gamma_k\ hourofday_{kt} + \theta MW_{t-24} + \sum_{j=1}^{J}\sum_{h=1}^{H}\rho_{jh} eventhour_{jht} + \sum_{j=1}^{J}\sum_{h=1}^{6}\varphi_{jh} preeventhour_{jht} + \sum_{j=1}^{J}\sum_{h=1}^{6}\omega_{jh} posteventhour_{jht} + \varepsilon_t$$

The right hand side variables in the model are defined as follows:

- *EvapTR72hour*$_t$ is the average evapo-transpiration rate over the previous 72 hours$_t$ at time t.
- *Temp24hour*$_t$ is the average temperature over the previous 24 hours at time t.
- *Rainfall24hour*$_t$ is the total rainfall over the previous 24 hours.
- *Weekofmonth*$_{wt}$ equals one if time t is in week w, w=1 to 3, and equals zero, otherwise. *Day*$_{dt}$, d=1 to 6, and *hourof day*$_{kt}$, k=1 to 23, are defined similarly.
- *Eventhour*$_{jht}$ equals one if time t is in hour h, h=1 to H, of event j, j=1 to J, and equals zero, otherwise. *Preeventhour*$_{jht}$ and *Posteventhour*$_{jht}$ are defined similarly.
- ε_t is the error term of the model representing random influences on the demand of customer i at time t.

The parameters to be estimated and their interpretations are as follows:

- ρ_{hj} is the impact of hour h of event j on demand. It is the difference between the estimate of what demand would have been if an event had not been called (reference load) and the actual demand in the hour.
- ω_{hj} is the impact of hour h after event j on demand. The coefficients capture any shifting of irrigation loads in response to the load control events.
- ϕ_{hj} is the impact of hour h before event j on demand. The coefficients capture any shifting of irrigation loads because of the load control events.
- α_0 is substation load at the omitted hour (Sundays at the 12 am hour in the first month).

- α_1 is the impact of average evapo-transpiration rate in the previous 72 hours on demand. α_2 shows the impact of temperature in the previous 24 hours on demand. α_3 measures the impact of rainfall in the previous 24 hours on demand.
- π_w, w=1 to 3, is the impact of week of month *w* on demand.
- δ_d, d=1 to 6, is the impact of day of the week *d* on demand.
- γ_k, k=1 to 23, is the impact of hour *k* on demand.

Appendix Table A.1. 2010 Estimated Hourly Load Reductions with 95 Percent Confidence Intervals

Date	Event	Hour	Estimated Load Reduction - Five substations (MW)	Lower Bound 95% Confidence Interval	Upper Bound 95% Confidence Interval	Estimated Load Reduction - All Idaho Irrigation (MW)	Opt-Out Adjusted Nominal Load	Opt-Out Adjusted Realization Rate
30-Jun	Event 1	Hour 1	-41.8	-55	-28	-54.3	168.4	24.8%
		Hour 2	-71.8	-86	-57	-93.2	168.4	42.6%
		Hour 3	-70.7	-86	-56	-91.8	168.4	42.0%
		Hour 4	-66.4	-82	-50	-86.3	168.4	39.5%
17-Jul	Event 2	Hour 1	-111.1	-125	-97	-144.3	182.8	60.8%
		Hour 2	-157.8	-172	-144	-204.9	182.8	86.3%
		Hour 3	-158.0	-172	-144	-205.2	182.8	86.4%
		Hour 4	-151.6	-166	-138	-196.9	182.8	82.9%
23-Jul	Event 3	Hour 1	-102.4	-116	-89	-133.0	184.0	55.7%
		Hour 2	-137.7	-152	-124	-178.9	184.0	74.9%
		Hour 3	-138.6	-153	-124	-180.0	184.0	75.3%
		Hour 4	-136.5	-150	-122	-177.2	184.0	74.2%
3-Aug	Event 4	Hour 1	-33.6	-42	-25	-43.6	181.5	18.5%
		Hour 2	-50.0	-58	-42	-65.0	181.5	27.6%
		Hour 3	-48.1	-57	-40	-62.5	181.5	26.5%
		Hour 4	-48.0	-56	-40	-62.4	181.5	26.5%
5-Aug	Event 5	Hour 1	-30.8	-39	-22	-40.0	181.0	17.0%
		Hour 2	-50.0	-59	-41	-65.0	181.0	27.6%
		Hour 3	-49.0	-58	-40	-63.7	181.0	27.1%
		Hour 4	-47.4	-56	-39	-61.6	181.0	26.2%
13-Aug	Event 6	Hour 1	-36.6	-45	-28	-47.6	184.2	19.9%
		Hour 2	-45.9	-54	-37	-59.6	184.2	24.9%
		Hour 3	-45.4	-54	-37	-58.9	184.2	24.6%
		Hour 4	-45.6	-54	-37	-59.2	184.2	24.7%

Notes: Estimates of load reductions for 5 substations based on regression model. Estimated load reductions for all Idaho Irrigation estimated as 5 substation load reduction divided by 0.77. Realization rate is the ratio of the estimated load reduction to the opt-out adjusted nominal load.

Appendix Table A.2. 2010 Estimated Hourly Load Reductions with 95 Percent Confidence Intervals

Date	Event	Hour	Block	Estimated Load Reduction - 5 Substations (MW)	Lower Bound 95% Confidence Interval	Upper Bound 95% Confidence Interval	Estimated Load Reduction - All Idaho Irrigation (MW)	Opt-out adjusted Nominal Load (MW)	Realization Rate	Nominal Load (MW)
29-Jun	Event 1	11:00 AM	11 AM - 1 PM	-32.7	-42.2	-23.1	-42.4	47.0	-69.6%	47.0
29-Jun	Event 1	12:00 PM	11 AM - 1 PM	-34.8	-44.0	-25.6	-45.2	47.0	-74.1%	47.0
29-Jun	Event 1	1:00 PM	11 AM - 1 PM	-28.3	-37.1	-19.5	-36.8	49.0	-57.8%	49.0
29-Jun	Event 1	2:00 PM	2 PM - 5 PM	-49.2	-58.9	-39.4	-63.8	84.8	-58.0%	89.3
29-Jun	Event 1	3:00 PM	2 PM - 5 PM	-87.0	-96.8	-77.2	-113.0	144.3	-60.3%	148.8
29-Jun	Event 1	4:00 PM	2 PM - 5 PM	-82.7	-92.5	-73.0	-107.5	144.3	-57.4%	148.8
29-Jun	Event 1	5:00 PM	2 PM - 5 PM	-75.8	-85.3	-66.3	-98.5	144.3	-52.6%	148.8
29-Jun	Event 1	6:00 PM	6 PM	-61.7	-70.9	-52.5	-80.1	110.1	-56.0%	110.1
8-Jul	Event 2	11:00 AM	11 AM - 1 PM	-48.7	-67.5	-29.9	-63.2	50.7	-96.0%	50.7
8-Jul	Event 2	12:00 PM	11 AM - 1 PM	-49.6	-67.9	-31.3	-64.4	50.7	-97.8%	50.7
8-Jul	Event 2	1:00 PM	11 AM - 1 PM	-39.0	-56.6	-21.4	-50.6	53.0	-73.6%	53.0
8-Jul	Event 2	2:00 PM	2 PM - 5 PM	-71.2	-90.3	-52.1	-92.4	90.5	-78.6%	96.5
8-Jul	Event 2	3:00 PM	2 PM - 5 PM	-119.8	-138.9	-100.6	-155.5	154.8	-77.4%	160.7
8-Jul	Event 2	4:00 PM	2 PM - 5 PM	-114.5	-133.5	-95.5	-148.7	154.8	-74.0%	160.7
8-Jul	Event 2	5:00 PM	2 PM - 5 PM	-104.9	-123.5	-86.2	-136.2	154.8	-67.8%	160.7
8-Jul	Event 2	6:00 PM	6 PM	-85.7	-103.7	-67.6	-111.3	118.9	-72.1%	118.9
15-Jul	Event 3	11:00 AM	11 AM - 1 PM	-41.3	-60.1	-22.5	-53.6	50.7	-81.4%	50.7
15-Jul	Event 3	12:00 PM	11 AM - 1 PM	-44.2	-62.6	-25.9	-57.4	50.7	-87.2%	50.7
15-Jul	Event 3	1:00 PM	11 AM - 1 PM	-43.1	-61.0	-25.2	-56.0	53.0	-81.3%	53.0
15-Jul	Event 3	2:00 PM	2 PM - 5 PM	-65.6	-84.7	-46.5	-85.2	76.6	-85.6%	96.5
15-Jul	Event 3	3:00 PM	2 PM - 5 PM	-107.0	-126.2	-87.8	-139.0	140.9	-76.0%	160.7
15-Jul	Event 3	4:00 PM	2 PM - 5 PM	-104.4	-123.5	-85.4	-135.6	140.9	-74.1%	160.7
15-Jul	Event 3	5:00 PM	2 PM - 5 PM	-100.1	-118.8	-81.4	-130.0	140.9	-71.0%	160.7
15-Jul	Event 3	6:00 PM	6 PM	-86.6	-104.7	-68.6	-112.5	118.9	-72.9%	118.9
16-Jul	Event 4	7:00 AM	7 AM- 10 AM	-37.5	-56.4	-18.6	-48.7	17.1	-219.1%	17.1
16-Jul	Event 4	8:00 AM	7 AM- 10 AM	-39.9	-58.3	-21.5	-51.8	17.1	-233.2%	17.1
16-Jul	Event 4	9:00 AM	7 AM- 10 AM	-35.2	-52.8	-17.5	-45.7	17.1	-205.5%	17.1
16-Jul	Event 4	10:00 AM	7 AM- 10 AM	-0.2	-8.8	8.3	-0.3	17.1	-1.4%	17.1
16-Jul	Event 4	11:00 AM	11 AM - 1 PM	0.0	-8.4	8.4	0.0	42.6	0.0%	42.6
16-Jul	Event 4	12:00 PM	11 AM - 1 PM	0.1	-8.0	8.2	0.2	42.6	0.3%	42.6
16-Jul	Event 4	1:00 PM	11 AM - 1 PM	0.4	-7.4	8.2	0.5	44.9	0.9%	44.9
16-Jul	Event 4	2:00 PM	2 PM - 5 PM	-60.6	-79.8	-41.5	-78.7	72.6	-83.5%	88.4
16-Jul	Event 4	3:00 PM	2 PM - 5 PM	-100.5	-119.8	-81.2	-130.5	135.9	-74.0%	151.7
16-Jul	Event 4	4:00 PM	2 PM - 5 PM	-98.6	-117.7	-79.4	-128.0	135.9	-72.5%	151.7
16-Jul	Event 4	5:00 PM	2 PM - 5 PM	-93.4	-112.2	-74.6	-121.3	135.9	-68.7%	151.7
16-Jul	Event 4	6:00 PM	6 PM	-77.7	-95.9	-59.6	-101.0	109.9	-70.8%	109.9
19-Jul	Event 5	7:00 AM	7 AM- 10 AM	-37.4	-56.2	-18.5	-48.5	17.1	-218.5%	17.1
19-Jul	Event 5	8:00 AM	7 AM- 10 AM	-40.2	-58.5	-21.8	-52.2	17.1	-234.9%	17.1
19-Jul	Event 5	9:00 AM	7 AM- 10 AM	-39.8	-57.5	-22.2	-51.7	17.1	-232.8%	17.1
19-Jul	Event 5	10:00 AM	7 AM- 10 AM	-18.1	-26.7	-9.5	-23.5	17.1	-105.8%	17.1
19-Jul	Event 5	11:00 AM	11 AM - 1 PM	-17.9	-26.3	-9.4	-23.2	42.6	-41.9%	42.6
19-Jul	Event 5	12:00 PM	11 AM - 1 PM	-16.7	-24.9	-8.6	-21.7	42.6	-39.3%	42.6
19-Jul	Event 5	1:00 PM	11 AM - 1 PM	-14.6	-22.4	-6.7	-18.9	44.9	-32.4%	44.9
19-Jul	Event 5	2:00 PM	2 PM - 5 PM	-61.3	-80.4	-42.2	-79.6	71.1	-86.2%	88.4
19-Jul	Event 5	3:00 PM	2 PM - 5 PM	-103.1	-122.3	-83.9	-133.9	134.5	-76.7%	151.7
19-Jul	Event 5	4:00 PM	2 PM - 5 PM	-101.2	-120.3	-82.2	-131.5	134.5	-75.3%	151.7
19-Jul	Event 5	5:00 PM	2 PM - 5 PM	-98.6	-117.3	-80.0	-128.1	134.5	-73.4%	151.7
19-Jul	Event 5	6:00 PM	6 PM	-83.3	-101.4	-65.3	-108.2	109.9	-75.8%	109.9

Date	Event	Hour	Block	Estimated Load Reduction - 5 Substations (MW)	Lower Bound 95% Confidence Interval	Upper Bound 95% Confidence Interval	Estimated Load Reduction - All Idaho Irrigation (MW)	Opt-out adjusted Nominal Load (MW)	Realization Rate	Nominal Load (MW)
20-Jul	Event 6	7:00 AM	7 AM- 10 AM	-46.4	-65.3	-27.5	-60.2	17.1	-271.1%	17.1
20-Jul	Event 6	8:00 AM	7 AM- 10 AM	-48.3	-66.6	-29.9	-62.7	17.1	-282.0%	17.1
20-Jul	Event 6	9:00 AM	7 AM- 10 AM	-44.4	-62.1	-26.8	-57.7	17.1	-259.7%	17.1
20-Jul	Event 6	10:00 AM	7 AM- 10 AM	-12.7	-21.4	-4.1	-16.5	17.1	-74.5%	17.1
20-Jul	Event 6	11:00 AM	11 AM - 1 PM	-13.6	-22.1	-5.2	-17.7	42.6	-32.0%	42.6
20-Jul	Event 6	12:00 PM	11 AM - 1 PM	-14.8	-23.0	-6.6	-19.2	42.6	-34.6%	42.6
20-Jul	Event 6	1:00 PM	11 AM - 1 PM	-15.1	-23.0	-7.3	-19.7	44.9	-33.7%	44.9
20-Jul	Event 6	2:00 PM	2 PM - 5 PM	-71.5	-90.7	-52.3	-92.9	65.2	-109.6%	88.4
20-Jul	Event 6	3:00 PM	2 PM - 5 PM	-105.4	-124.8	-86.1	-136.9	128.6	-82.0%	151.7
20-Jul	Event 6	4:00 PM	2 PM - 5 PM	-102.0	-121.2	-82.8	-132.5	128.6	-79.3%	151.7
20-Jul	Event 6	5:00 PM	2 PM - 5 PM	-98.0	-116.9	-79.1	-127.3	128.6	-76.2%	151.7
20-Jul	Event 6	6:00 PM	6 PM	-82.2	-100.5	-63.9	-106.7	109.9	-74.8%	109.9
26-Jul	Event 7	7:00 AM	7 AM- 10 AM	-32.9	-51.7	-14.0	-42.7	17.1	-192.1%	17.1
26-Jul	Event 7	8:00 AM	7 AM- 10 AM	-36.1	-54.5	-17.8	-46.9	17.1	-211.3%	17.1
26-Jul	Event 7	9:00 AM	7 AM- 10 AM	-35.0	-52.6	-17.3	-45.4	17.1	-204.3%	17.1
26-Jul	Event 7	10:00 AM	7 AM- 10 AM	-10.4	-18.9	-1.8	-13.5	17.1	-60.7%	17.1
26-Jul	Event 7	11:00 AM	11 AM - 1 PM	-11.0	-19.3	-2.6	-14.2	42.6	-25.7%	42.6
26-Jul	Event 7	12:00 PM	11 AM - 1 PM	-11.1	-19.3	-3.0	-14.4	42.6	-26.1%	42.6
26-Jul	Event 7	1:00 PM	11 AM - 1 PM	-12.2	-20.0	-4.4	-15.9	44.9	-27.2%	44.9
26-Jul	Event 7	2:00 PM	2 PM - 5 PM	-54.7	-73.8	-35.6	-71.0	76.9	-71.1%	88.4
26-Jul	Event 7	3:00 PM	2 PM - 5 PM	-89.7	-108.9	-70.5	-116.5	140.3	-63.9%	151.7
26-Jul	Event 7	4:00 PM	2 PM - 5 PM	-88.8	-107.9	-69.7	-115.3	140.3	-63.3%	151.7
26-Jul	Event 7	5:00 PM	2 PM - 5 PM	-85.3	-104.1	-66.5	-110.8	140.3	-60.8%	151.7
26-Jul	Event 7	6:00 PM	6 PM	-75.8	-94.1	-57.5	-98.4	109.9	-69.0%	109.9
26-Jul	Event 8	7:00 AM	7 AM- 10 AM	24.1	14.1	34.0	31.3	17.1	140.8%	17.1
2-Aug	Event 8	8:00 AM	7 AM- 10 AM	25.3	15.6	34.9	32.8	17.1	147.7%	17.1
2-Aug	Event 8	9:00 AM	7 AM- 10 AM	29.7	20.4	38.9	38.6	17.1	173.5%	17.1
2-Aug	Event 8	10:00 AM	7 AM- 10 AM	-2.4	-6.6	1.7	-3.1	17.1	-14.1%	17.1
2-Aug	Event 8	11:00 AM	11 AM - 1 PM	-2.0	-6.1	2.0	-2.6	42.6	-4.8%	42.6
2-Aug	Event 8	12:00 PM	11 AM - 1 PM	-2.1	-6.0	1.8	-2.7	42.6	-4.9%	42.6
2-Aug	Event 8	1:00 PM	11 AM - 1 PM	-3.1	-6.8	0.6	-4.0	44.9	-6.9%	44.9
2-Aug	Event 8	2:00 PM	2 PM - 5 PM	11.6	1.5	21.7	15.1	83.6	13.9%	88.4
2-Aug	Event 8	3:00 PM	2 PM - 5 PM	3.8	-6.3	14.0	5.0	146.9	2.6%	151.7
2-Aug	Event 8	4:00 PM	2 PM - 5 PM	-3.0	-13.1	7.0	-3.9	146.9	-2.1%	151.7
2-Aug	Event 8	5:00 PM	2 PM - 5 PM	-6.7	-16.5	3.2	-8.6	146.9	-4.5%	151.7
2-Aug	Event 8	6:00 PM	6 PM	1.3	-8.2	10.9	1.7	109.9	1.2%	109.9
5-Aug	Event 9	7:00 AM	7 AM- 10 AM	-8.0	-18.0	2.0	-10.4	16.9	-47.3%	16.9
5-Aug	Event 9	8:00 AM	7 AM- 10 AM	-8.7	-18.4	1.0	-11.3	16.9	-51.4%	16.9
5-Aug	Event 9	9:00 AM	7 AM- 10 AM	-6.9	-16.2	2.4	-9.0	16.9	-41.0%	16.9
5-Aug	Event 9	10:00 AM	7 AM- 10 AM	-8.2	-12.4	-3.9	-10.6	16.9	-48.5%	16.9
5-Aug	Event 9	11:00 AM	11 AM - 1 PM	-8.3	-12.5	-4.2	-10.8	42.0	-19.9%	42.0
5-Aug	Event 9	12:00 PM	11 AM - 1 PM	-8.6	-12.6	-4.7	-11.2	42.0	-20.5%	42.0
5-Aug	Event 9	1:00 PM	11 AM - 1 PM	-10.0	-13.7	-6.2	-12.9	44.2	-22.5%	44.2
5-Aug	Event 9	2:00 PM	2 PM - 5 PM	-19.3	-29.5	-9.2	-25.1	79.6	-24.3%	87.1
5-Aug	Event 9	3:00 PM	2 PM - 5 PM	-41.7	-51.9	-31.5	-54.2	142.0	-29.4%	149.6
5-Aug	Event 9	4:00 PM	2 PM - 5 PM	-42.2	-52.4	-32.0	-54.8	142.0	-29.7%	149.6
5-Aug	Event 9	5:00 PM	2 PM - 5 PM	-39.1	-49.1	-29.1	-50.8	142.0	-27.5%	149.6
5-Aug	Event 9	6:00 PM	6 PM	-31.5	-41.2	-21.9	-41.0	108.3	-29.1%	108.3
24-Aug	Event 10	7:00 AM	7 AM- 10 AM	-25.5	-35.5	-15.6	-33.2	16.9	-151.4%	16.9
24-Aug	Event 10	8:00 AM	7 AM- 10 AM	-24.9	-34.6	-15.2	-32.3	16.9	-147.6%	16.9
24-Aug	Event 10	9:00 AM	7 AM- 10 AM	-22.1	-31.4	-12.9	-28.8	16.9	-131.3%	16.9

Date	Event	Hour	Block	Estimated Load Reduction - 5 Substations (MW)	Lower Bound 95% Confidence Interval	Upper Bound 95% Confidence Interval	Estimated Load Reduction - All Idaho Irrigation (MW)	Opt-out adjusted Nominal Load (MW)	Realization Rate	Nominal Load (MW)
24-Aug	Event 10	10:00 AM	7 AM- 10 AM	-5.0	-9.3	-0.7	-6.5	16.9	-29.6%	16.9
24-Aug	Event 10	11:00 AM	11 AM - 1 PM	-5.2	-9.3	-1.0	-6.7	42.0	-12.3%	42.0
24-Aug	Event 10	12:00 PM	11 AM - 1 PM	-5.5	-9.5	-1.5	-7.1	42.0	-13.1%	42.0
24-Aug	Event 10	1:00 PM	11 AM - 1 PM	-6.0	-9.8	-2.2	-7.8	44.2	-13.5%	44.2
24-Aug	Event 10	2:00 PM	2 PM - 5 PM	-32.0	-42.1	-21.9	-41.6	81.9	-39.1%	87.1
24-Aug	Event 10	3:00 PM	2 PM - 5 PM	-40.8	-50.9	-30.6	-52.9	144.3	-28.2%	149.6
24-Aug	Event 10	4:00 PM	2 PM - 5 PM	-39.0	-49.0	-28.9	-50.6	144.3	-27.0%	149.6
24-Aug	Event 10	5:00 PM	2 PM - 5 PM	-41.3	-51.1	-31.4	-53.6	144.3	-28.6%	149.6
24-Aug	Event 10	6:00 PM	6 PM	-31.8	-41.3	-22.3	-41.3	108.3	-29.4%	108.3
26-Aug	Event 11	7:00 AM	7 AM- 10 AM	-20.4	-30.4	-10.5	-26.5	16.9	-121.1%	16.9
26-Aug	Event 11	8:00 AM	7 AM- 10 AM	-19.0	-28.7	-9.3	-24.7	16.9	-112.7%	16.9
26-Aug	Event 11	9:00 AM	7 AM- 10 AM	-18.4	-27.6	-9.1	-23.8	16.9	-108.8%	16.9
26-Aug	Event 11	10:00 AM	7 AM- 10 AM	-2.5	-6.7	1.7	-3.2	16.9	-14.8%	16.9
26-Aug	Event 11	11:00 AM	11 AM - 1 PM	-2.0	-6.0	2.1	-2.6	42.0	-4.7%	42.0
26-Aug	Event 11	12:00 PM	11 AM - 1 PM	-2.6	-6.5	1.2	-3.4	42.0	-6.3%	42.0
26-Aug	Event 11	1:00 PM	11 AM - 1 PM	-2.5	-6.2	1.2	-3.3	44.2	-5.7%	44.2
26-Aug	Event 11	2:00 PM	2 PM - 5 PM	-31.9	-42.0	-21.8	-41.5	84.0	-38.0%	87.1
26-Aug	Event 11	3:00 PM	2 PM - 5 PM	-44.3	-54.4	-34.1	-57.5	146.4	-30.2%	149.6
26-Aug	Event 11	4:00 PM	2 PM - 5 PM	-40.5	-50.6	-30.4	-52.6	146.4	-27.7%	149.6
26-Aug	Event 11	5:00 PM	2 PM - 5 PM	-37.1	-47.0	-27.1	-48.1	146.4	-25.3%	149.6
26-Aug	Event 11	6:00 PM	6 PM	-30.6	-40.2	-20.9	-39.7	108.3	-28.2%	108.3